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Effect of reservoirs heterogeneity on injection pressure and placement of preformed particle gel for conformance control

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EFFECT OF RESERVOIRS HETEROGENEITY ON INJECTION PRESSURE AND PLACEMENT OF PREFORMED PARTICLE GEL FOR CONFORMANCE CONTROL

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ABSTRACT

Preformed particle gels (PPG) have been successfully applied as a plugging agent for plugging fractures and then divert displacing fluid into poorly swept zones. However, PPG propagation and plugging mechanisms through open fractures have not been studied thoroughly.

This work investigated the influence of some factors (particle size, brine concentration, heterogeneity, and brine salinity) on gel injectivity, plugging performance for water flow through open fractures. Five-foot tubes were used to mimic open fractures. Three models were designed to conduct the work, including (1) single fracture with uniform fracture width, (2) single fracture with different widths, and (3) two parallel fractures with different width ratios. Results from single uniform fracture experiments showed that PPG injection pressure was more sensitive to gel strength than gel particle size. When large PPG size and high gel strength were used, high injection pressure and large injection pore volume were required for PPG and brine to reach fracture outlets. Results from single heterogeneous fracture model experiments showed PPG injection pressure increased as the fracture heterogeneity in sections increased. Existence of choke point caused injection pressure to increase accordingly. Furthermore, results showed that injecting lower salinity water, which was less than the brine salinity that was used to prepare PPG, would improve the PPG plugging efficiency for water flow. Parallel fracture models results showed that gel strength and fracture width ratio can effect PPG injection selectivity.

In summary, this work demonstrated a few important impacting elements of gel propagation and water flow for different heterogeneous open fractures situations.

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NOMENCLATURE

Symbol	Description
μ_l	Water leak-off rate
k_{gel}	Gel permeability to water
Δp	Pressure drop
w_f	Fracture width
μ	Water viscosity

1. INTRODUCTION

Heterogeneity within a reservoir is one of the primary reasons for that neither primary nor secondary recovery mechanisms can retrieve large amounts of hydrocarbon recovery. Water channeling, one of the primary reservoir conformance problems, is caused by reservoir heterogeneities that lead to the development of high-permeability streaks and fractures. High permeability contrast caused by streaks, fractures, conduits, and fracture-like features can expedite undesirable water channeling and early water breakthrough during water flooding. These high-conductivity areas inside the reservoir only occupy a small fraction of the reservoir, but they capture a significant portion of injected water. As a result, large amounts of oil remain un-swept as large water injections bypass oil-rich un-swept zones/areas.

Gel treatments have been proved to be a cost-effective chemical conformance control technology that can be used to reduce the fluid flow in these large open features. The application of this technology can assist with controlling water production, significantly increasing oil production, and extending the economic life of a reservoir.

A gel treatment's success depends heavily on the gel's ability to extrude through fractures and channels during the placement process. Thus, understanding the mechanism, performance, and behavior of gel propagations and plugging efficiencies through these high permeability streaks is the key to a successful conformance control treatment. Water blocking, another primary mechanism for gel treatment to increase oil recovery, also worth significant attention.

Being increasingly popular for conformance control application, PPG treatment has been reported showing positive result in most of its applications (Liu et al., 2006).

However, few studies have been conducted to probe the performance or the mechanism of PPG propagation and water blocking in Super-K formation, fractures and large void space conduit systems.

In this thesis, a work was conducted to deeply examine several factors that impact the PPG propagation mechanism, placement performance, and conformance control in open fracture systems. It discusses how PPG size, brine concentration, fracture heterogeneity, brine salinity, and ratio of particle size to fracture width can affect PPG injection and resistance to water flow through fracture. Based on this study's findings on the effect of the factors just described, this study gives valuable advice for designing PPG injection treatment plans.

2. LITERATURE REVIEW

This section focuses on providing background information for the research. The first part will demonstrate an introduction of gel treatment, especially from the chemical aspect. The second part will discuss about the gel treatment mechanisms for reservoir with fractures, mainly by citing the works done by other researches.

2.1. AN INTRODUCTION OF GEL TREATMENT

After primary- and secondary-oil-production, almost two thirds of oil-in-place is left underground. Recovery of this considerable portion of oil has been a highlighted topic for many years. It became especially heated these decades because of the declining of newly discovered oil resources. In this case, advanced improved oil recovery (IOR) or enhanced oil recovery (EOR) technologies are playing key roles to produce the remaining oil in mature oilfields. Generally, EOR methods are classified into three categories, gas injection, thermal recovery and chemical injection.

Thermal recovery. Taking thermal recovery as an example, it is mainly applicable to heavier crude oil. Considered as gravity less than 20° API, held in relatively permeable, shallow sands formation, heavy oil occupies 70% of global crude oil storage. According to IEA, boosting oil recovery of these heavy crude oil could unlock around 300 billion barrels of oil. Thermal recovery take advantage of a mechanism that by heating crude oil, to reduce its viscosity and even vaporize some part of crude oil. Heated oil has lower surface tension and enjoys more permeability in formation. All the effort aims at decreasing mobility ratio and increasing sweep efficiency, thus enhancing oil recovery.

Gas injection. Gas injection (such as nitrogen, natural gas, carbon dioxide and hydrogen chloride) is the most widely applied enhanced oil recovery process for light oil. It is considered as injecting gas into well pattern to push oil out. The most desirable situation is miscible gas flood. Injected gas and crude oil form one-phase flow in reservoir. Several mechanisms can be achieved, including reducing oil viscosity, oil partially vaporization, reducing interfacial tension and swelling crude oil. To reach miscible gas flood, minimum miscible pressure (MMP) is required. When reservoir pressure is higher than MMP, near-miscible or immiscible condition will appear. Under these conditions, oil recovery can also be improved by oil swelling and reducing viscosity.

Chemical injection. Chemical EOR methods generally include polymer flooding, alkaline/surfactant flooding, gel treatment and foam flooding. These chemical injection EOR methods aim at correcting reservoir heterogeneity or controlling fluid mobility, on this basis, increase sweep efficiency to reduce residual-oil saturation.

Polymer flooding is the most commonly applied chemical EOR method. It can effectively increase sweep efficiency by (1) reducing viscous fingering, (2) improving water-injection profile, (3) making afterwards water flooding more effective, (4) reducing the relative permeability of water flow more than the permeability of oil flow.

Foam flooding is usually considered as alternately injecting gas and surfactant solution, or injecting supercritical gas with surfactant dissolved in it. Foam flooding is used to reduce gas mobility and to correct reservoir heterogeneity and increase sweep efficiency during gas injection. Rock wettability can be changed to desiring water-wet when using certain kinds of surfactant in typical reservoirs.

2.1.1. An Introduction of Gel Treatment. Gel treatment is designed to solve excess water production problems, which is a crucial issue for mature oil fields. Being a commonly used and cost-effective method, polymer gel have two main mechanisms: 1) blocking high-permeability zones and 2) reducing permeability disproportionally (DPR). These injected gel can create high resistance in high permeability zone and more desirably divert a portion of injected water to areas not previously swept by water. When the second mechanism is active, gel treatment can decrease the permeability to water flow with a larger extent than to oil or gas flow.

2.1.1.1 In situ polymer gel. In the 1970s, Needham from Philips Co. synthesized the first in situ polymer gels with partially hydrolyzed polyacrylamides (HPAM) and aluminum citrate (Needham et al., 1974). The in situ gel systems have two main components: high molecular weight polymers and crosslinkers. When crosslinking happening, the crosslinking agent will connect to two adjacent polymer molecules chemically or physically linking them together. An in-situ three-dimensional network is formed under reservoir conditions. The network has a liquid-like behavior on molecular length scales while maintaining solid-like macroscopic properties.

According to crosslinker properties, they can be classified into two categories: metallic and organic crosslinked systems.

Metal crosslinked PAM system. Polyacrylamide in its pure state has a neutral electrical property and comprises a carbon-carbon backbone with amide groups. A large amount of the amide groups tend to convert to carboxylate groups, when exposed to alkaline solution or vulnerable to elevated temperature. Ionic bonding can form between itself and multivalent cations under this situation. The metal ions can associate with

ligands. These ions can further react with carboxyl groups. When metal ion-carboxyl groups further associates with another carboxyl group on the same polymer chain, intramolecular crosslinks will be initiated. Intermolecular crosslinks build up and continue to build up a three-dimensional network if the concentration of metal ion-carboxyl groups is higher than or equal to the critical overlap concentration (Al-Assi et al., 2006).

The milestone of in situ gel, especially for metal crosslinked gel system, is invention of a new polymer-gel system using HPAM/Cr(III) acetate. It is established and patented by Sydansk from Marathon Oil Co.. One of the most important improvements is that the gelation time of this gel system is controllable, because the forces between Cr(III) and acetate, carboxyl groups can slow the crosslinking reaction time. According to Sydansk, this gel system is insensitive to pH from about 2 to 12.5. Moreover, the system can keep effective under high temperature (124^{o}C or even higher) (Sydansk and Smith, 1988).

Organically crosslinked PAM-related system. Chang et al., synthesized a PAM gel based on the crosslinking reaction between phenolic compounds and formaldehyde. This system aimed at solving the harsh reservoir environment problems, such as high temperature, high salinity and high pH (Chang et al., 1985; Chang et al., 1987). Polyethyleneimine (PEI) has been used as a kind of organic crosslinker for PAM-based polymer gels to provide thermally stability (Al-Muntasheri et al., 2009).

According to a review of worldwide field applications of the organically crosslinked polymer/gel (OCP) system, this system have the following advantages: 1) low-viscosity system, 2) adequate pumping time, 3) effective water permeability

reduction, 4) thermal stability and 5) robustness (Eoff et al., 2007). All these strengths have made OCP system one of the most effective methods of water shut-off.

However, in situ gels have many drawbacks that cannot be ignored. One of the most crucial problems is that with a plenty of optimization, in situ gel system lack time control for gelation time. This weakness may cause problems for placing the gel into certain layers or distance from injection wellbores. Being vulnerable to shear degradation, dilution by formation water and gelant composition leak-off are also limitations for application in situ gels (Chauveteau et al., 2001; Coste et al., 2000; Portwood, 1999; Ganguly et al., 2001).

2.1.1.2 Preformed particle gels (PPG). Preformed gel is formed at surface facilities before injection, and then injected into reservoir. No gelation occurring in reservoirs. The current available preformed gels types include preformed particle gel (PPG) (Bai et al., 2004; Bai et al., 2007; Coste et al., 2000), microgels (Chauveteau et al., 2001; Chauveteau et al., 2003; Zaitoun et al., 2007), pH sensitive crosslinked polymer (Al-Anazi and Sharma, 2002; Huh et al., 2005), mm-sized swelling polymer (Abbasy et al., 2008; Larkin and Creel, 2008), and Bright WaterTM (Frampton et al., 2004; Pritchett et al., 2003). Major difference between these preformed gel types are their sizes, swelling times and the applicative reservoir condition.

Preformed particle gels. Bai et al. initiated preformed particle gel (PPG) conformance control technology in PetroChina to solve the problems caused by fractures or high permeability zones. It is a particled superabsorbent crosslinking polymer that can swell to 200 times of its primary size in brine. Acrylamide and N, N'-methylenebisacrylamide are used as monomer and crosslinker respectively to synthesize

the particle gels. Then PPG are dried, crushed and sieved to get solid states and desired sizes. Comparing with general in situ gels, PPG have advantages listed as following. 1) PPGs' strength and size can be controlled and be friendly to environment. They are stable with the existing of almost all reservoir minerals and water salinities. 2) PPG can preferentially enter fracture or fracture-feature channels and at the same time declining gel penetration into low permeability zones. 3) PPG has only one component during injection. 4) PPG can be prepared using water produced from field without influencing gel stability. Enjoying all these strong points, PPG, especially millimeter-size PPG has been approved successful to reduce water production problems or to reduce polymer production problems in more than 2000 wells in China. (Bai et al., 2008; Liu et al., 2006).

Microgels. Chauveteau et al. synthesized a type of preformed microgels, which is reported to be fully water soluble, non-toxic, soft, stable and size-controlled. The microgel is prepared using a terpolymer of acrylamide containing 2% acrylates and 2% sulfonated groups from SNF Floerger. The first type of the microgels use environmentally friendly zirconium crosslinker. The second type of microgels are covalently crosslinked. These types of microgels can the plugging problem during injection in situ HPAM/zirconium (IV) acetate, which is caused by gel forming and bridging at pore throat and absorbing to form a gel layer. A typical microgel size is about 1-3 μm and typical gel concentration is 3,000 ppm (Chauveteau et al., 2000 and 2001). Their results showed that the microgels can be injected into a porous media with a permeability of 6 Darcy core without any sign of continuous plugging (Zaitoun et al., 2007).

Submicro-sized particle gels (Bright Water^{TM}). A novel submicro-sized particle gel system has been proposed by both Pritchett et al. (Pritchett et al., 2003) and Frampton et al. (Frampton et al., 2004) for conformance control problems. These gels can be injected into a thief zone which has a several-hundred-millidarcy permeability and block the thief zone; an in-depth fluid diversion result can be achieved during the water injection after gel placement. The key feature of this submicro-sized particle gels system is the microgels with thermo-responsive properties. When being injected into the formation, the gels can result in a spontaneous temperature increase, the labile cross-linker in the gel network begins to de-crosslink. The cross-linking density of particle gels decreases and thus allowing the particle gels expand aggressively by absorbing more surrounding fluids.

2.2. GEL TREATMENT IN RESERVOIR WITH FRACTURES

The high permeability contrast issue caused by fractures contributes to low sweep efficiency and excess water production. It is reported that reducing fracture conductivity can increase production oil cut (Graue et al., 2002). Reduction of flow in fractures or super-permeability channels after gel placement has been reported in further studies (Seright, 1995, 2003a, 2003b; Sydansk, 1990; Sydansk and Southwell, 2000). In order to optimize of gel treatment, investigating gel behaviors (injection, propagation, water blocking, leak-off, dehydration) when propagating through fracture becomes important. Fortunately, these topics have been investigated for decades by researchers. In this part, results and conclusion got by pioneers will be cited and discussed.

2.2.1. Studies of Gels Water Blocking Property. The problem of excess water production is common. This issue can cause poor economic results because of water disposition, operational spending and oil productivity loss. The excess produced water can also causes environmental issues (Vasquez et al., 2005; Simjoo et al., 2009). Seright et al. summarized factors that influence the performance of water flow reduction of a blocking material injection: 1) the distance that the blocking agent could transport into formation, 2) permeability reduction and 3) the flow geometry (Seright et al. 2001).

In the case that gel treatments are mainly applied for excess water blocking and permeability reduction, the mechanisms of gels blocking water worth significant effort to investigate. Their blocking behavior was reported to be affected by porous media permeability, treatment volume, temperature, crosslinker concentration and gel strength (Jeroen et al. 2001). Core flooding experiments were conducted to investigate the ability of the gel to reduce permeability of sandpacks and cores after gel treatment as well as their ability to resist water flow which helps to enhance oil production (Stavland et al., 1995; Al-Muntasheri et al., 2006). The gel with high mechanical strength were approved to be efficient in shutting off water to a large extent (Baisali et al., 2011).

Seright et al. reported that the permeability reduction properties of gels depended on whether they are "strong" or "weak" gels (Seright et al., 1995). Strong gels were demonstrated that could reduce the permeability of different porous rocks to approximately the same value. **Table 2.1** was showed by Seright et al. to indicate the comparison of different blocking agents' selectivities in entering high- versus low-permeability zones.

Table 2.1. Comparison of placement properties in the two-layer linear system with a 1:10 permeability contrast.

Blocking agent	Distance in low-k zone/distance in high-k zone	
	Without crossflow	With crossflow
Gelant		
1. Low viscosity	0.10	0.10
2. High viscocity	0.32	0.99
Particulates		
3. Small parcitles	0.10	0.10
4. Intermediate-sized particles	0.00	0.00
Gelant with particles		
5. Small particles	0.10	0.10
6. Intermediate-sized particles	0.01	0.01
7. Large particles	0.99	0.99

Seright et al. argued that particulates mainly blocking water by two mechanisms: 1) particulates could form a filter cake on the surface of rocks, 2) using the relation between particle size and the pore sizes of the zones and particles' selective penetrating ability (Seright et al., 2001). The level of water blocking is composed by two

components: 1) forming a filter cake formed at the external surface of a certain formation zone and 2) forming an "internal filter cake" inside the porous medium by the particles trapped in the pore throats. They also stated that to enable the particle gel provideing superior performance water blocking, the particles should 1) be small enough for transporting into the high permeability zones, 2) be large enough to form external filter cakes on the low permeability zones, 3) have a narrow size distribution, 4) not aggregate or adsorb excessively on pore walls.

2.2.2. Gels Propagation in Fractured Reservoir. The mechanisms of gel transporting in porous media were summarized as compression, micro flow and pseudo two-phase flow (Jeroen et al., 2001). However, when transporting through fractures, gel treatment for conformance control has significant differences with propagation through matrix.

2.2.2.1 In situ gel propagation through fractured reservoir. In situ gels have been proved to be effective both in decrease excess water production (Rousseau et al., 2005; Portwood, 1999) and oil recovery improvement (Portwood, 2005; Demir et al., 2008). In situ gels may enter a fractured formation in its immature form (gelant) or preformed mature form. The injected states depend on conditions such as wellbore heating, pumping time (Brattekås et al., 2015). The two gel states have totally different propagation mechanisms.

Gelant. The immature state of bulk gel, gelant, has low viscosity and small particles. Seright et al. argued that gelant consist of an aqueous solution with one or more reactive components, which react to form an immobile gel. The properties, such as low

viscosity allow gelant to flow through the rock matrix as well as fractures and relatively low pressure gradient are needed to reach extrusion (Seright, 1995; Seright et al., 2003). Darcy equation and fractional-flow theory can be used to calculate the distance of gelant transporting into reservoir. These calculations demonstrate that gelants can flow deep into all open zones, not just those zones highly saturated with water (Seright et al., 2001). Ganguly et al. investigated gelant in fractured cores, with or without intrusion into matrix (Ganguly et al., 2002). According to their research, gelant penetrated rock matrix and formed a zone of homogeneous concentrated gel. However for the gelant, which did not penetrate into matrix, no gelation was detected. Zou et al. and Ganguly et al. both suggested gelant might experience compositional changes when contacting reservoir fluids or rock that may interfere with gelation (Zou et al., 2000; Guaguly et al., 2002). Seright processed experiments testing gelant (gelated for 0.1 hours) penetrating porous rock (Seright, 1995). Gelants can penetrate readily into porous rock before gelation happen significantly. Less volume of gelant penetrate into matrix with the increasing of gelation. At the same time period, gel propagation become slower and more negligible. Bryant et al. reported that the movement of chemical components of a gelant through the formation highly depends on the chemical interactions with the formation and other components.

Being a significant concern for using in situ gel, leak-off issue has been a heated topic for decades. In situ gel components leaking into matrix can not only cause formation damage but also gelation problems cause by insufficient elements (Seright, 1995). A pH changing in formation is also reported by Ganguly et al (Ganguly et al., 2002). Letting more gelation to occur before the gelant leaves the wellbore and adding

gel or particulate matter to the gelant are two methods for minimizing leak-off (Seright, 1995). To achieve desired gelant, programmable gelation time, good injectivity, good propagation of the chemical components and a durable permeability reduction were all needed.

In situ gel after gelation (Bulk gel). After gelation, gelant forms mature gel, it also can be called bulk gel. Comparing with liquid-like gelant, mature gel become much more rigid and more stable. The process of mature gel intrusion into matrix is extremely slow and negligible (Brattekås et al., 2015). Because of its structure, mature gel is inhibited from passing through pore throats (Seright, 2001). Significant pressure gradient is needed to propagate mature gel through fractures (Seright, 1999). Cr (III)-acetate-HPAM gel did not extrude through low-to-medium-conductivity fracture, when low-pressure gradients were applied (Seright, 1999).

To study the mechanism for mature gel propagation through fractures, Seright et al. injected one-day-old Cr(III)-acetate-HPAM gel through a 48-inch-long Berea sandstone core with a 1.5-inch-width fracture inside it (Seright et al., 1999). The setup is showed in **Figure 2.1** and **Figure 2.2**. During injection, Pressure increased at all taps and kept stable values after injecting 60 FV (fracture volumes) gel. All effluent extruded through fracture at first 15 fracture volumes and then started extrude from matrix. Pressure gradient is the reason for gel dehydration and forming filter cake, which have an extremely low permeability, on the surface between matrix and fracture. Components of effluent were constant with injected gel. Gel stayed in fracture became immobile and still keep the same composition. These two evidences indicate propagation through fracture under pressure gradient does not change in situ gel composition.

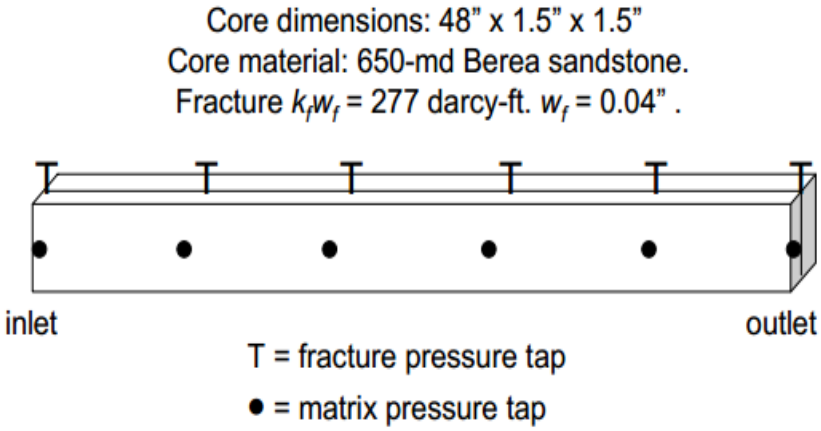


Figure 2.1. Illustration of the fractured core.

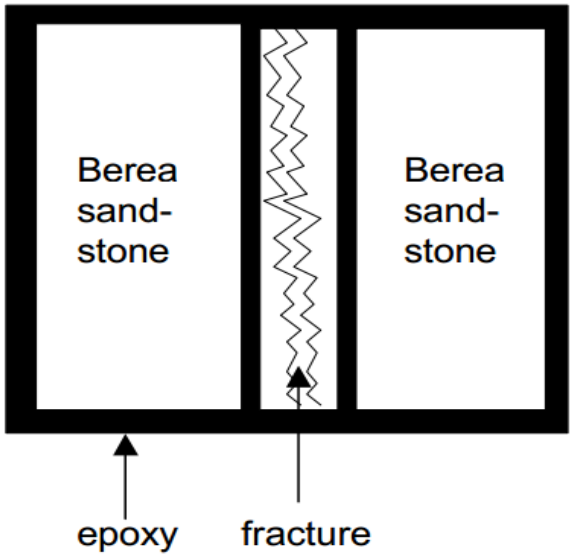


Figure 2.2. Transection of the fractured core.

The same with leak-off issue to gelant, dehydration under pressure gradient is a crucial concern for mature gel. Some gel dehydrated and became immobile (Seright, 1995). The leak-off rate is defined as,

$$\mu_l = 2k_{gel}\Delta p/(w_f\mu)$$

Where μ_l is water leak-off rate, k_{gel} is gel permeability to water, Δp is pressure drop, w_f is fracture width, μ is water viscosity (Seright, 1999). Seright also reported (Seright, 1999). degree of dehydration is insensitive to permeability of the rock adjacent to the fracture. During gel extrusion through fracture of given width, gel dehydration was proven to be independent of position and velocity. According to Seright, they also argued that increasing fracture width could weaken gel dehydration.

2.2.2.2 Preformed particle gel propagation through fractured reservoir.

Being increasingly popular in gel treatment, PPG treatment has been reported showing positive result in most of its applications (Liu et al., 2006). Qiu et al. argued that PPG increased oil production rate from 14.3% to 50% and decreased water production to the range of 0.4% to 4.7% for being applied for 655 wells from 2001 to 2012 (Qiu et al. 2014). To better understand mechanisms for PPG to improve oil recovery, researchers have carried out many studies to clarify its propagation mechanisms.

To fully understand PPG propagation in fractures, researchers started from situation in matrix or non-fracture formation. Bai et al. investigated PPG transportation in porous media (Bai et al., 2007a, 2007b). Visible micromodel and sandpack were used as transparent media. Six patterns of PPG transporting behavior were reported: direct pass, adsorption, deform and pass, snap-off and pass, shrink and pass, trap. Their results also showed four consecutive processes during the progress of a gel particle through a pore throat, which had a size smaller than the particles. The processes can be summarized as moving to entrance, particle losing water by being squeezed, particle being stretched and passing through the throat.

These processes are illustrated in **Figure 2.3** and will be used in the following sections to explain the results. Moreover, their results using simplified porous media model showed six consecutive processes, which are illustrated in **Figure 2.4**.

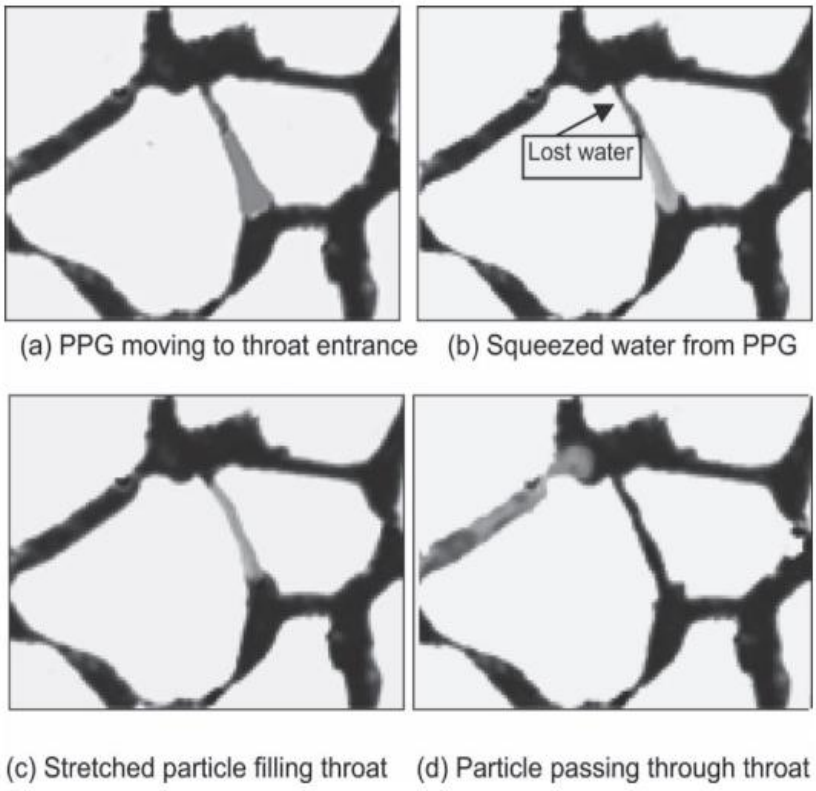


Figure 2.3. A process of a particle transporting through a throat.

Rousseau et al. tested microgels propagation using sandpacks (Rousseau et al. 2005). Microgels were reported to form a thick adsorbing layer that can reduce permeability. Also, shear thinning behavior was reported during passing the porous media.

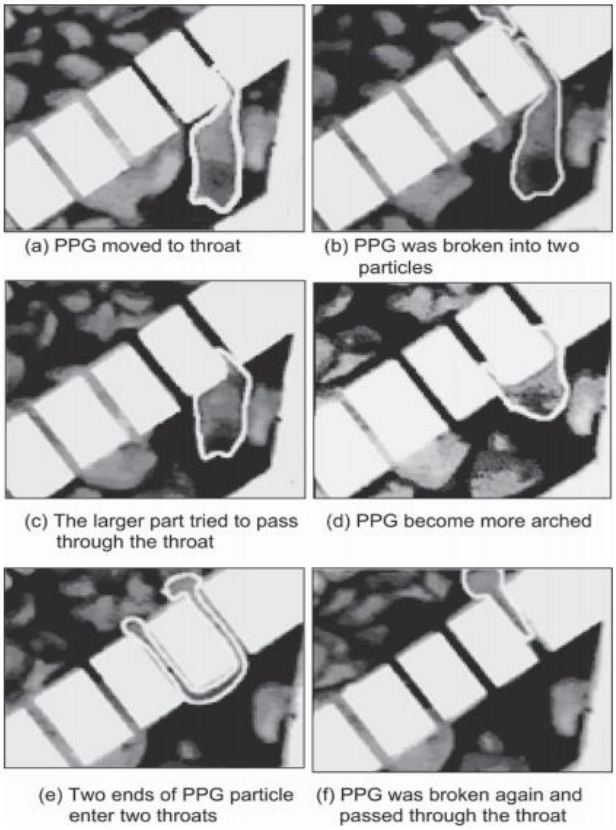


Figure 2.4. A process of a particle transporting through throats at the simplified model.

A few studies have been conducted to evaluate the performance or the mechanism of PPG propagation in fractures or super-permeability zones. Zhang et al. used transparent models to visually track swollen PPG propagation through open fractures (Zhang et al., 2010). How factors (brine concentration, flow rate, fracture width) affect PPG injectivity and brine injection were investigated. **Figure 2.5** shows PPG was showed to move like a piston in fracture. Being similar to bulk gel, after placement in fracture, PPG formed gel pack. Brine could break through gel pack and create several channels to allow water to pass through. Moreover, another similar point between PPG and in situ gel is that both of them have the ability to reduce different-width fractures' permeability to the same level (Zhang et al., 2010; Seright and Martin, 1993). However, they argued that

comparing with in situ gel, PPG suffered much less dehydration during injection. The PPG dehydration decreased with increasing of injection rate, fracture width and brine concentration.

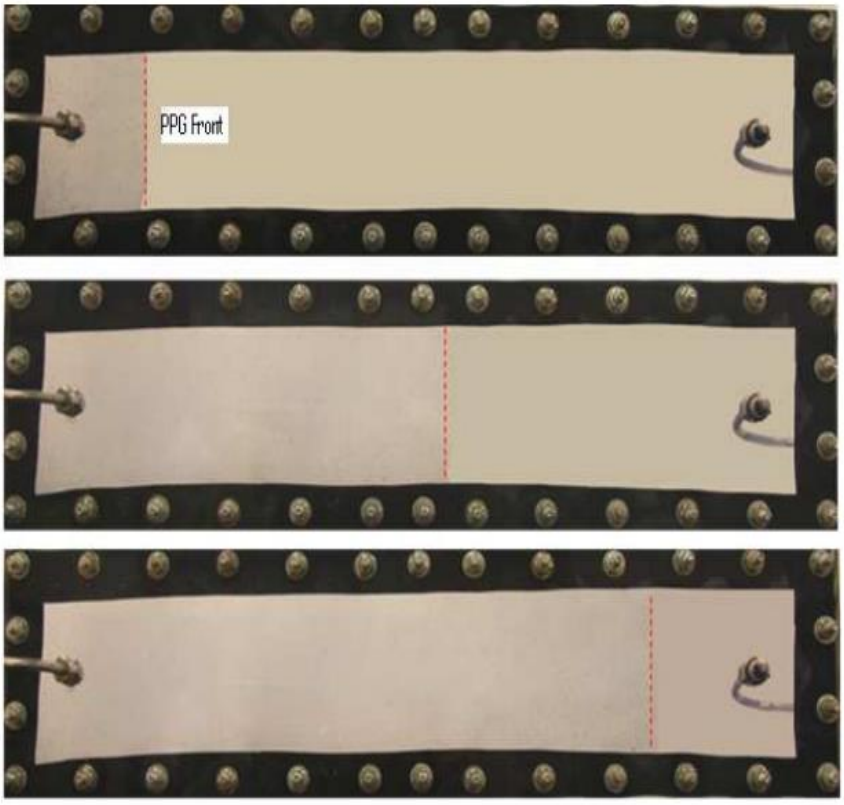


Figure 2.5. Gel movement during gel injection into fracture model.

Imqam et al. investigated PPG injection and placement mechanisms through conduits or large channels under conditions where the channel opening size was larger than, equal to, or smaller than the swollen PPG size (Imqam et al., 2015c). Their results indicated that PPG strength affected injectivity more significantly than did the particle opening ratio. They also reported the size of PPG was reduced during transporting through channels due to both dehydration and breakdown.

Additional work was conducted to examine which factors significantly effect on PPG resistance to water flow. Imqam and Bai designed a large transparent channel to understand the resistance of PPG to water flow (Imqam and Bai, 2015). They reported that PPG did not fully block the channel but rather formed a permeable gel pack along the channel model.

Further work was also conducted by Imqam et al. to evaluate the PPG injection and resistance to water flow through Super-K permeability formations (Imqam, 2015e). They found the blocking efficiency of PPG to water flow increased as the strength, size, and concentration of the PPG increased. These previous studies showed that PPG resistance to water flow is sensitive to gel strength. The assumption of having salinity within a reservoir differ from PPG salinity has led to the hypothesis that different degrees of salinities would affect preformed particle gel strength and blocking efficiency to water flow.

The effect of PPG injection on conformance results in heterogeneity formation was investigated previously by Imqam et al. (Imqam, 2015b; Imqam, 2015d). They investigated how PPG can be used effectively to correct the non-cross flow heterogeneity problem within a reservoir. They observed that PPG injection significantly reduced the high permeability core and formed a permeable gel filter cake into low permeability cores. As a result, a large amount of oil was recovered after PPG injection. These two studies however, showed a need to conduct more work to understand factors and mechanisms which control PPG flow into high permeability features rather than the flow into low permeability features.

3. EFFECT OF RESERVOIRS HETEROGENEITY ON PROPAGATION AND PLACEMENT OF PREFORMED PARTICLE GEL TREATMENT

3.1. EXPERIMENTAL MATERIALS

PPG. A commercial superabsorbent polymer was used as a PPG to conduct the experiments in this research. It is a crosslinked polyacrylic acid/polyacrylamide copolymer. Dry particles with sizes of 600-850 micron, 180-300 micron, and 100-125 micron were used.

Brine. Three brine solutions were used in experiments: NaCl solution, Daqing formation water, Shengli formation water. **Table 3.1** shows the formation water compositions for Daqing and Shengli oil fields.

Table 3.1. Oil field formation water compositions as measured in 3 Liter Units.

Formula	Daqing formation water (grams)	Shengli formation water (grams)
NaCl	13.200	21.330
$NaHCO_3$	2.670	
Na_2SO_4	0.690	
KCl	0.282	
$CaCl_2$		0.792
$CaCl_2 \cdot 2H_2O$	1.053	
$MgCl_2 \cdot 6H_2O$	1.005	
H_2O	2981.100	2977.878

3.2. EXPERIMENT SETUP AND PROCEDURES

Three fracture apparatus models were designed to evaluate how PPG injectivity and blocking efficiency to water flow are influenced by brine concentration, particle size, heterogeneity, brine salinity change, and ratio of particle size to fracture width (Dg/Wf).

In addition, more work was performed to understand how changing brine concentration, formation of field water, and dry particle gel sizes affect PPG swelling ratio, deswelling ratio, and gel strength.

3.2.1. First Model: Single-fracture Homogeneous Apparatus Description. A single-fracture homogeneous model with same fracture width geometry was designed to understand the effect of PPG rheology on the injection process. **Figure 3.1** provides a schematic of the single fracture model used to conduct the experiments. The model was designed to determine the effect of brine concentration and particle size on PPG injectivity and blocking efficiency to water flow.

A five-foot stainless tube with an internal diameter being 1.752 mm formed the fracture. The model contained a syringe pump that was used to inject brine and PPG through the accumulator into a five-foot tube. The tube was divided into three sections: The first two were two feet long, and the last section was one foot long. Three pressure taps were placed between each two sections. Effluent gel and brine were both collected to evaluate the gel's properties after propagation.

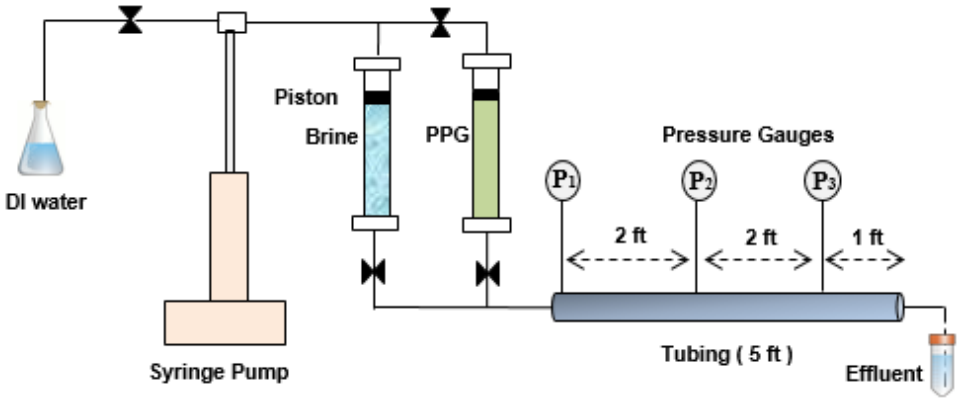


Figure 3.1. First model: homogeneous single-fracture experiment setup.

Experimental procedure. Dry PPG samples of 600-850 micron size were placed separately in 1% NaCl, 0.05% NaCl, Daqing formation water, and Shengli formation water and left overnight to swell fully. A sieve was used to allow the swollen gel to separate from the excess brine solution. The gel then was packed into a stainless steel accumulator so that it could be injected into a fracture model. A fracture with a width of 1.752 mm was used in this experiment. The gel injection steps are summarized as follows:

1) The PPG samples were injected into the single fracture model using 9 injection velocities in sequence. The velocities and pump rates were shown in **Table 3.2**. The gel initially was injected at a high velocity of 1930 ft. /day (1 ml/min), which was then reduced gradually for all experiments. Injection pressure needed to be stable for each gel injection velocity.

2) Before PPG injection, fractures were filled with brine. At the beginning of injection, when the first brine drop extruded from outlet, the pressure was monitored and recorded as threshold pressure.

Table 3.2. PPG injection velocities and pump rates conversion table (1.752 mm ID tubes).

Injection velocities (ft. /day)	Pump rates (ml/min)
1931.26	1
1448.44	0.75
965.63	0.5
482.81	0.25
241.4	0.125
193.12	0.1
96.56	0.05
48.28	0.025
9.65	0.005

3) Following pressure stabilization, extruded gel samples were taken for each gel injection velocity to measure gel strength and particle size.

4) Finally, when the gel injection process was complete, brine with the same concentration for preparing PPG was injected initially into the fracture using a velocity of 48 ft. /day (0.025 ml/min). A second cycle using a different concentration of brine was injected later with an injection velocity of 48 ft. /day. Brine cycles were injected to determine how PPG blocking efficiency to water would be affected.

The above steps were repeated for PPG sizes of 180-300 and 100-125 micron swollen in 1% NaCl to determine particle size effect on both PPG injection and blocking performance.

3.2.2. Second Model: Single-fracture Heterogeneity Apparatus Description. A heterogeneous fracture model was designed to simulate fractures with changing-width geometry. **Figure 3.2** shows the heterogeneity fracture apparatus used to conduct the experiments. The model was designed to determine the effect of width change within single-fracture on PPG injectivity. It also attempted to determine effect of changing brine salinity on PPG resistance to water flow.

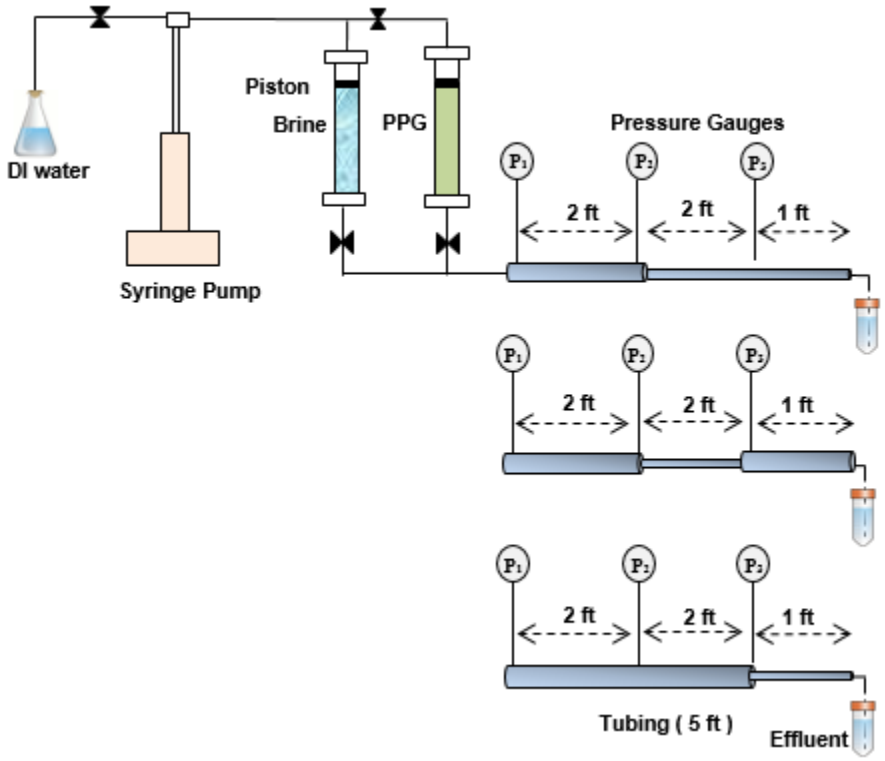


Figure 3.2. Second model: heterogeneous single-fracture experiment setup.

Table 3.3 summarizes the three designs of fracture heterogeneity. Two fracture widths were used in these three designs, a larger width of 1.752 ft. and a smaller width of 0.774 ft. The first design has the larger fracture width in first 2 feet but goes to the smaller width in the remaining 3 feet of the fracture. The second design has only smaller fracture width in the middle 2 feet of the fracture. The third design maintains the larger fracture width until the last foot of the fracture model. A syringe pump was used to inject brine and PPG through the accumulator into the designed fractured models. Effluent gel and brine were both collected to evaluate the gel properties after extrusion.

Table 3.3. Single-fracture heterogeneous models used in experiments.

Single-fracture heterogeneity #	Fracture width (mm)		
	First 2 ft.	Second 2 ft.	Last 1 ft.
First design (change width of last three feet)	1.752	0.774	0.774
Second design (change width of middle two feet)	1.752	0.774	1.752
Third design (change width of last one foot)	1.752	1.752	0.774

Experimental procedure. Dry PPG samples of 600-850 micron size were swollen in 1% NaCl were used for injection process. The PPG was injected at a high velocity

(1,930 ft. /day), which then was reduced gradually for all experiments. At each injection velocity, a stable pressure was achieved. Threshold pressure was also recorded.

When the gel injection process was complete, a 1% NaCl solution was injected at a velocity of 48 ft. /day to determine PPG resistance to water flow. A 0.05% NaCl was injected later at a velocity of 48 ft. /day to determine the effect of changing salinity on PPG blocking efficiency to water flow. This procedure was performed for all three fracture designs.

In the first design, we conducted more experimental work to see if increased injection water salinity affected injection pressure. To achieve that, PPG samples were swollen in 0.05% NaCl and injected into the fractures at a velocity of 1930 ft. /day until pressure became stable. Then, first cycle of 0.05% NaCl was injected at 48 ft. /day until pressure became stable. Later, a second cycle of increased concentration brine of 1% NaCl was injected at same velocity.

3.2.3. Third Model: Parallel Fracture Apparatus Description. A parallel model was designed to simulate multiple channels/fractures within reservoir had different fracture widths. Both of the tubes have the same composition with single fractures. The different is the widths of two tubes were different. There is one inlet for both of the tubes. **Figure 3.3** illustrates the schematic of the parallel fracture model used to perform the experiments.

The model was designed to determine the effect of non-cross flow heterogeneity fractures on PPG injectivity performance. It aims to understand what factors control the PPG flow into large pore throat sizes and how these factors can be adjusted to reduce the PPG flow into small pore throat sizes.

A PPG of 600-850 microns were swollen in brine concentrations of 1% NaCl, 0.05% NaCl, and 0.005% NaCl and were prepared separately for these experiments.

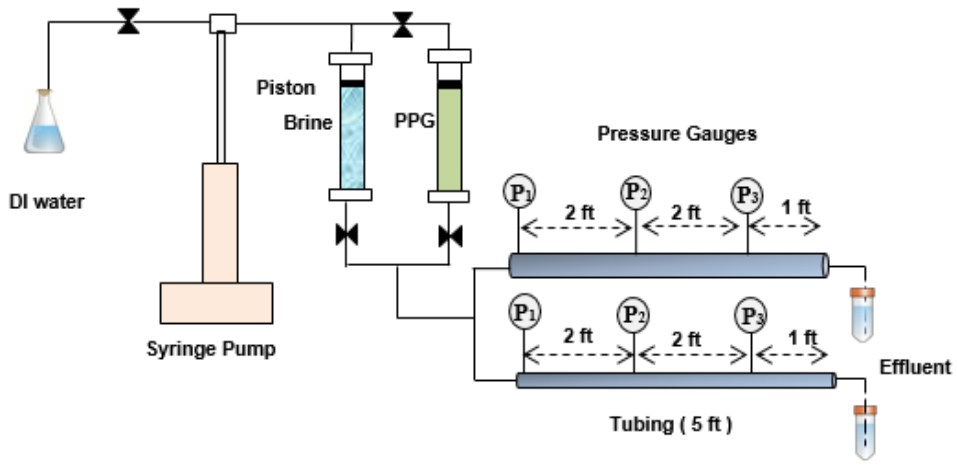


Figure 3.3. Third model: Parallel fractures experiment setup.

Table 3.4 summarizes the fracture design models used in this investigation. Four fracture heterogeneity models were designed based on gel strength and width ratio for two parallel fractures. Gel strength controls the ratio of PPG size to fracture width (Dg/Wf). The first three design models had different gel strengths, but had the same fracture width ratio (1.739). The fourth model was designed to test the effect of fracture width ratio when it compared to Model Experiment # 1. A syringe pump was used to inject brine and PPG through the accumulator into designed fractured models. Effluent gel and brine were collected separately from each fracture design to evaluate gel properties after extrusion.

Table 3.4. Parallel fractures models used in experiment.

Model Experiment #	NaCl, %	PPG strength, pa	Fracture width (mm)	Fracture width ratio	Particle diameter after swelling (Dg), mm	Dg/Wf
1	1	850	1.752	1.739	3.2	1.826
			3.048			1.050
2	0.05	517	1.752	1.739	4.88	2.785
			3.048			1.601
3	0.005	360	1.752	1.739	5.86	3.344
			3.048			1.923
4	1	850	0.774	3.937	3.2	4.134
			3.048			1.050

Experimental procedure. PPG samples were injected into both fracture models at the same time, from the same inlet. The PPG samples were injected at a high velocity (1930 ft. /day) and then reduced gradually for all experiments. Threshold pressures were recorded. At each injection velocity, the stable pressure was achieved along both fracture widths. The PPG produced from each fracture was monitored and collected during the injection process.

3.3. RESULTS AND ANALYSIS OF PPG INJECTION

This section discusses PPG injection and blocking behavior results obtained from the three experiment apparatus models. Single-fracture homogenous model examines the

effect of PPG size and brine concentration. Single-fracture heterogeneity and parallel-fracture models study the effect of fracture heterogeneity.

3.3.1. Single-fracture Homogeneous Model Results. The following results discuss the effect of PPG size and brine concentration on both PPG injection and blocking behavior mechanism.

3.3.1.1 Effect of PPG size on PPG injection. Injection pressure is a significant element for gel treatment design. The injection pressure indicates if injecting the PPG is easily to process.

The injectivity and plugging efficiency can be optimized by control parameters, such as PPG size and brine concentration. The following figures show the pressure conducted by the pressure taps versus injection pore volume (PV). From the figures, PPG injection and propagation process can be studies in details.

Figure 3.4 shows injection pressure measurements of a 600-850 microns in diameter PPG swollen in 1% NaCl. This PPG was injected into fractures at a constant velocity of 1 ml/min. PPG injection pressure was plotted as a function of PPG injection pore volume. Injection pressures across fractures slightly increased at the first 50 injected pore volumes (PVs) of PPG injection. The injection pressure across the fracture was not substantially varied with a consistent readings of approximately 40 psi across the fracture. This could be explained as a result of the fracture smoothness and PPG dehydration mechanisms, which occurred during the early stage of PPG injection. Once the effect of dehydration lessened after 50 PVs of PPG injection, the injection pressure started to increase sharply along fracture. The injection pressure continued to increase until the PPG produced at an effluent which can be seen by the small drop of injection

pressure at approximately 100 PVs of PPG injection. Injection pressure continued again to rise and became stable at approximately 300 psi, 180 psi, and 78 psi at sensors P1, P2, and P3, respectively. Results also show a pressure drop across fracture sections as being almost equal, indicating that PPG uniformly blocked/reduced the permeability of fracture.

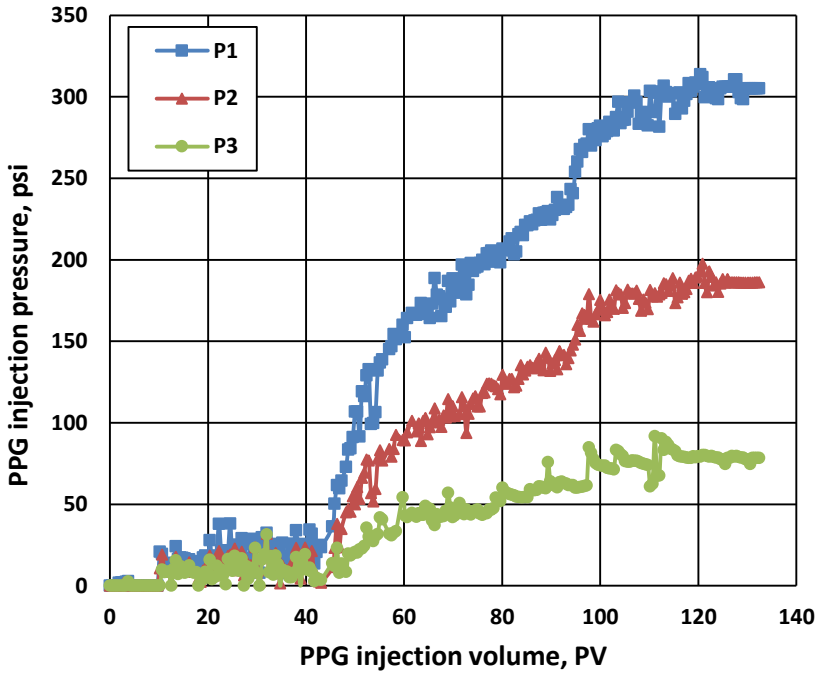


Figure 3.4. PPG injection pressure in homogeneous fracture model (first model, 600-850 micron, 1% NaCl, 1ml/min).

Figure 3.5 shows injection pressure measurements of a 180-300 microns in diameter PPG swollen in 1% NaCl. The same injection procedures were repeated. PPG injection pressure was plotted as a function of PPG injection pore volume. Injection pressure slightly increased during the first 18 PV, which is less than the 50 PV in 600-850 micron size PPG. This might because smaller size PPG have lower threshold pressure and suffer less dehydration. For pressure monitored by P1 and P2, pressure

increased suddenly at 7.4 PV. This could be explained by the blocking in the fracture, which is caused by assembly of particles.

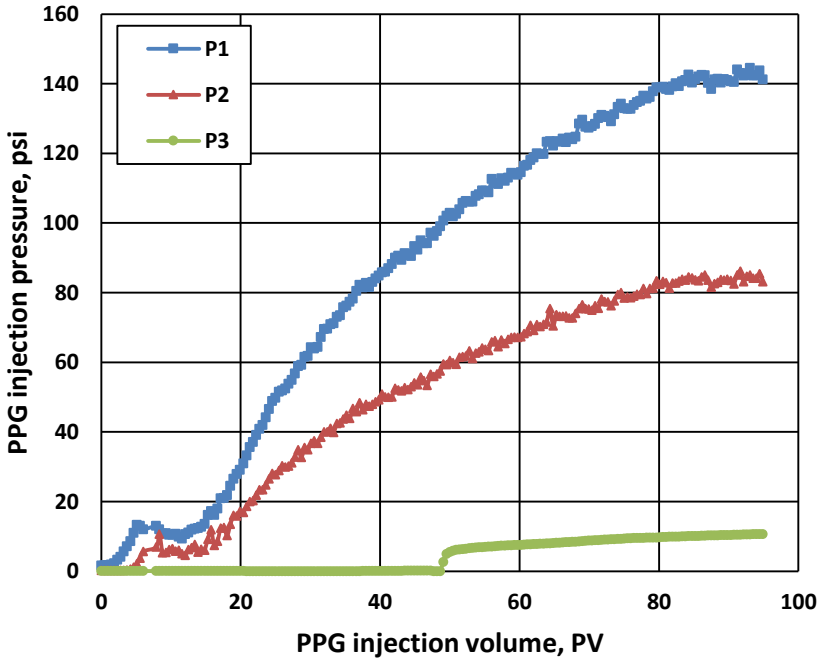


Figure 3.5. PPG injection pressure homogeneous fracture model (first model, 180-300 micron, 1% NaCl, 1ml/min).

The pressure increased significantly after 18 PV PPG has been injected. Injection pressure kept rising and became stable at 140 psi, 85 psi, and 10.5 psi at sensors P1, P2, and P3. The stable pressures were much less than the ones monitored in **Figure 3.4**. From the equal pressure drops between each section, PPG placement could be confirmed as uniformly.

Figure 3.6 shows injection pressure measurements of a 100-125 microns in diameter PPG swollen in 1% NaCl.

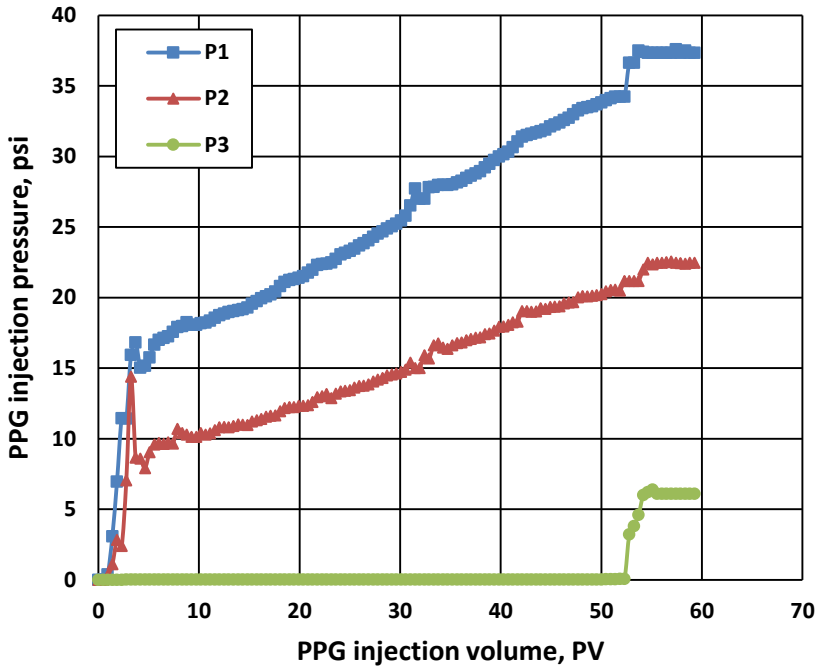


Figure 3.6. PPG injection pressure in homogeneous fracture model (first model, 100-125 micron size PPG, 1% NaCl).

The pressure and injection PV relation was plotted in **Figure 3.6**. For pressure monitored at P1 and P2, it increased at the beginning of injection. This phenomenon is constant with the one happened in 180-300 micron size PPG injection, which is when PPG particle size is smaller, the pressure starts to raise earlier. It indicates that when swollen PPG has smaller size, the threshold pressure is lower, so particles can enter fracture earlier and easier, moreover, less dehydration happened at the same time. During injection the pressure kept rising and became stable at 37 psi, 22 psi, and 6 psi at sensors P1, P2, and P3. The stable pressures were much less than the ones monitored in 600-850 and 180-300 micron size PPG injection.

The pressure results are shown by **Table 3.5**. From the table, conclusion can be summarized that 1) for PPG swollen in same brine solution, when PPG has larger size, the threshold pressure is higher; 2) larger size PPG has higher injection stable pressure

than smaller size PPG; 3) for larger size PPG, more pore volume is needed to inject to reach stable pressure.

Table 3.5. Effect of particle sizes on PPG injection.

PPG size, micron	PPG threshold pressure, psi	PPG stable pressure, psi			Volume needed to get stable pressure (PV)		
	P1	P1	P2	P3	Section 1	Section 2	Section 3
600-850	26	305	186	77.5	129	124	115
180-300	12.5	142	82.7	10.4	92.5	90	87.5
100-125	7	37	22.5	6.1	57	56	55.4

Effect of injection flow rate. After PPG was placed into the fracture, PPG was injected with another eight velocity rates to obtain the effect of velocity on injection stable pressure measurements. For each PPG injected velocity, stable pressure was achieved for all the three sections. **Figure 3.7** shows PPG stable injection pressure measurements for three PPG sizes swollen in 1% NaCl as a function of gel velocity. Results suggest that stable injection pressure increased as the gel sizes increased as long as gel particles were swollen in the same brine solution. For all gel particle sizes, PPG

injection stable pressure increased insignificantly after reaching a velocity of 500 ft. /day implying that gel slip occurred when PPG extruded through fractures at high velocity rates. For PPG samples with particles 600-850 microns in diameter, stable injection pressure increased from 270 psi to 312 psi when injection velocity increased from 1450 ft. /day to 1930 ft. /day.

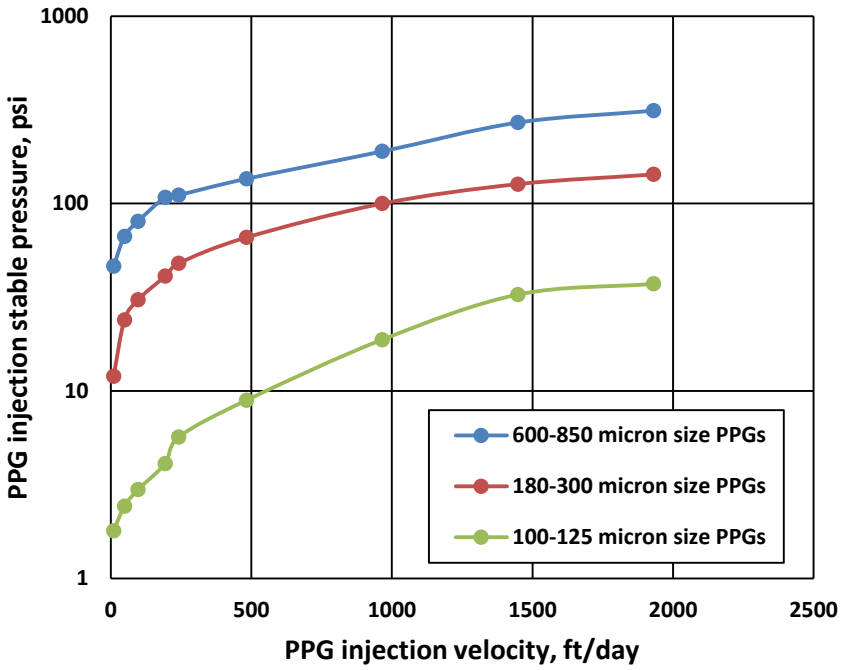


Figure 3.7. PPG injection pressure for different gel particle sizes swollen in 1% NaCl solution at different velocities.

3.3.1.2 Effect of brine concentration on PPG injection. PPG is sensitive to brine concentration because of the brine solution effect on PPG swelling ratio and gel strength (Imqam et al., 2014 and 2016).

Figure 3.8 shows PPG injection pressure measurements for 600-850 micron-sized PPG swollen in 0.05 % NaCl. PPG was injected into fractures at a constant velocity of 1930 ft. /day.

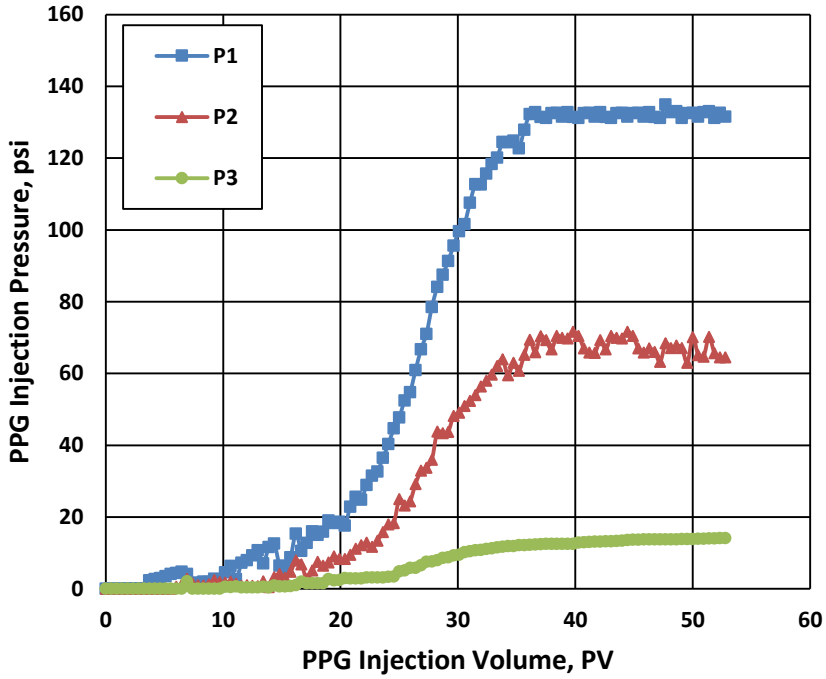


Figure 3.8. PPG injection pressure in homogeneous fracture model (first model, 600-850 micron, 0.05% NaCl, 1ml/min).

Injection pressure across the fracture was recorded as a function of PPG injection pore volume. Injection pressure did not increase significantly along fractures until reaching 20 PV of PPG injection. PPG became more concentrated because of water loss and as a result injection pressure starting to rise substantially until stabilizing at 131 psi, 64 psi, and 14 psi at sensors P1, P2, and P3, respectively. Comparing with 600-850 micron size PPG swollen in 1% NaCl solution, the pressures here are much lower. PPG experienced significant dehydration, delay its movement and propagation through fracture. **Figure 3.8** indicates that the PPG front reached sensor P2 after being injected by

approximately 7 PV and reached sensor P3 after approximately 15 PV. However, the dehydration was controllable if proper PPG strength and size were selected. Results also illustrate that pressure drop between fracture sections were approximately equal, which implies that PPG reduced the permeability across fractures at almost the same level.

Figure 3.9 shows PPG injection pressure measurements for 600-850 micron-sized PPG swollen in Daqing formation water (total dissolved solid equal to 6.3 g/L). PPG was injected into fractures at a constant velocity of 1930 ft. /day. The relation between pressure and injection PV was plotted. After increase slightly in first 23 PV, injection pressure starting to rise significantly and stabilizing at 289 psi, 178 psi, and 51 psi at sensors P1, P2, and P3. The pressure here is much higher than PPG swollen in 0.05% NaCl and close to the one for 1% NaCl.

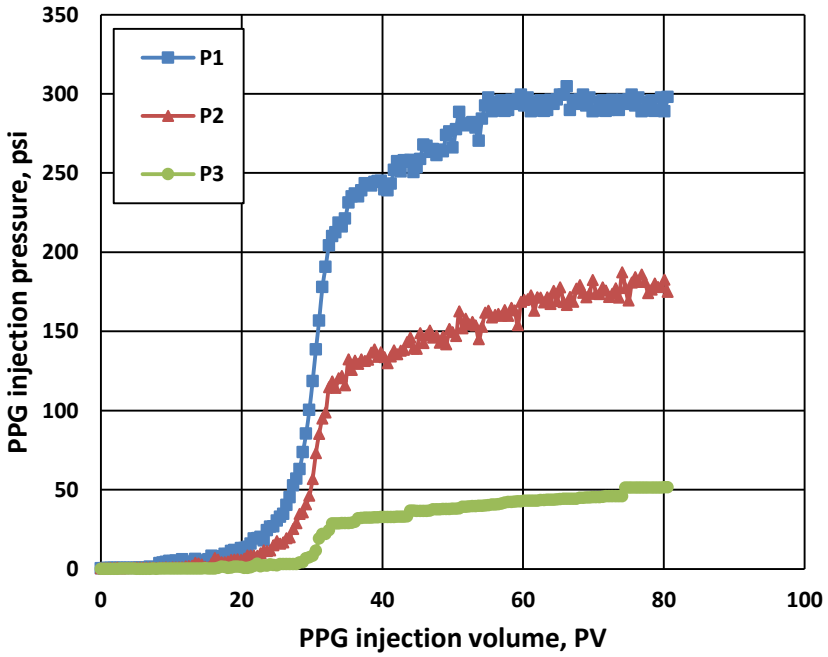


Figure 3.9. PPG injection pressure in homogeneous fracture model (first model, 600-850 micron size PPG, Daqing formation water).

Figure 3.10 shows PPG injection pressure measurements for 600-850 micron-sized PPG swollen in Shengli formation water (total dissolved solid equal to 7.2 g/L). PPG was injected into fractures at a constant velocity of 1930 ft. /day. The relation between pressure and injection PV was plotted. Injection pressure stablized at 296 psi, 179 psi, and 75 psi at sensors P1, P2, and P3. The pressure here is much higher than PPG swollen in 0.05% NaCl and close to the ones for 1% NaCl and Daqing formation water. From Figure 3.9 and Figure 3.10, PPG reduced the permeability across fracture by same level, according to the similar pressure drop between fracture sections.

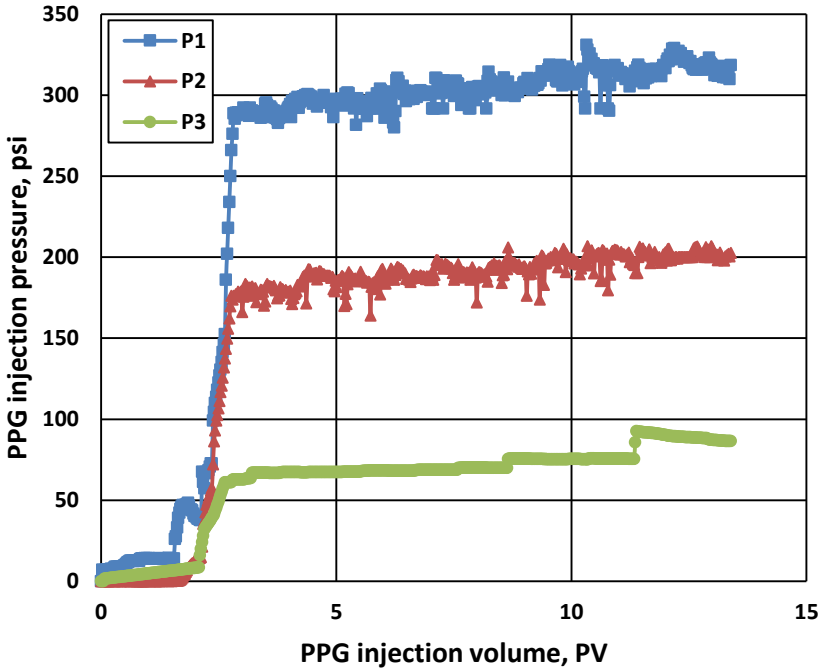


Figure 3.10. PPG injection pressure in homogeneous fracture model (first model, 600-850 micron, Shengli formation water).

Table 3.6 summarizes experiment results obtained for gel particles swollen in four different kinds of brine solutions. Gel particles swollen in low NaCl concentration needed less threshold pressure than gel particles swollen in high NaCl. This happened

because PPG swollen in low NaCl became more deformable and had less strength than PPG swollen in high NaCl.

Table 3.6. Effect of particle sizes on PPG injection.

Brine solution properties	PPG threshold pressure, psi	PPG stable pressure, psi			Volume needed to get stable pressure (PV)		
	P1	P1	P2	P3	Section 1	Section 2	Section 3
0.05 % NaCl	9.3	131	64	14	51	48	43
1% NaCl	26	305	186	77	134	129	120
Daqing Formation Water	15	289	178	51	75	74.8	73.5
Shengli Formation Water	17	296	179	75	82	80.5	80.5

Stable PPG injection pressure decreased as NaCl concentration decreased. Injection pressure for gel particles swollen in a brine 1% NaCl became stable at 305 psi and it became stable at 131 psi when gel particles swollen in a brine of 0.05% NaCl. Since gel particles swollen in low NaCl concentration are more injectable, they required

less injection pore volume to propagate deep into fractures compared with gel particles swollen in high NaCl.

Effect of injection flow rate. PPG continued to be injected into fractures at the other eight different velocity rates. For each PPG injected velocity, stable pressure was achieved for all the three sections. **Figure 3.11** shows PPG stable injection pressure measurements for PPG swollen in 0.05% NaCl, 1% NaCl, Daqing formation water, and Shengli formation water as a function of gel injection velocity. PPG swollen in 0.05% NaCl were more injectable than any of other PPG.

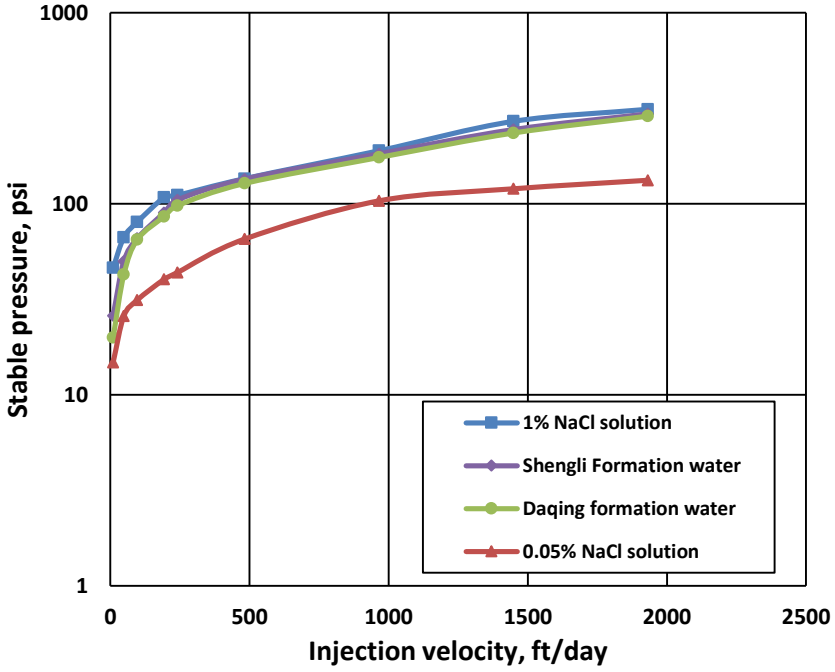


Figure 3.11. PPG injection pressure for PPG swollen in different brine solutions.

Interestingly, PPG swelled in low brine concentration had larger size particles than PPG swelled in high brine concentrations, yet had better injectivity. This occurred because when PPG is swollen in low brine solutions its particle size increased but its

strength decreased as well. The other PPG samples had almost the same injection stable pressure because their gel strengths were not so different. Therefore, these results bring attention to the PPG injection design where PPG strength is more important to consider than PPG size. Results also show that the stability of pressure in PPG injections did not increase linearly with increase of PPG injection velocity but instead injection pressure became independent of injection velocity after reaching a velocity of 500 ft. /day.

Referring to the PPG injection pressure results obtained from PPG size and brine concentration effects, it should be noted that brine concentration is a more important factor than particle size itself. Yes, it was observed that PPG injection pressure increased as PPG size increased but these results were for gel particles swollen in the same brine solution. In other words, this PPG had the same gel strength.

More experiments were added to the core flooding experiments to gain a deeper understanding of the effect of PPG size and brine concentration. Samples of dry PPG were placed in transparent test tubes filled with different brine solutions to measure their swelling ratio and strength. A dry PPG with the size of 600-850 microns was swollen in four brine solutions of 0.05% NaCl, 1% NaCl, Daqing formation water, and Shengli formation water. In addition, three PPG samples with particle sizes of 600-850, 180-300, and 100-125 microns were swollen in 1% NaCl.

Figure 3.12 and **Figure 3.13** show swelling ratio measurements focusing on both brine concentrations and PPG sizes. **Figure 3.12** indicates that the swelling ratio increased as brine solution salinity increased. However, dry PPG swollen in oilfield formation water remained in the same swelling ratio range, because these brine solutions had similar salinity. **Figure 3.13** shows that the swelling ratio for different PPG sizes.

Interestingly, PPG swelling ratio was not affected by changing PPG sizes as long as they swelled in the same brine solution.

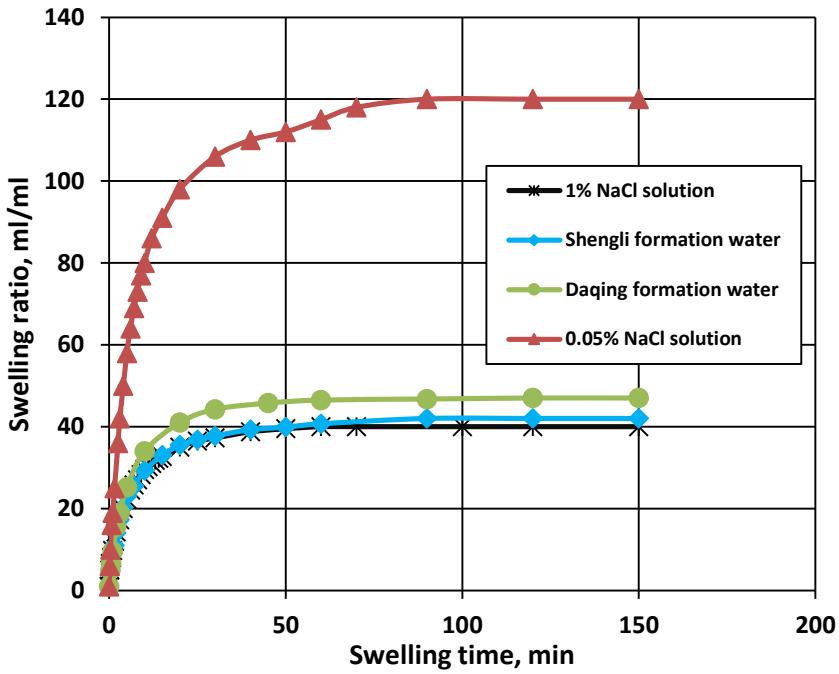


Figure 3.12. Swelling ratios in different brine solutions.

To further study the effect of brine concentration and PPG size, after gel particles were fully swollen, their strengths were measured using a rheoscope instrument. The instrument is mentioned in Experiment Setup section. **Figure 3.14** and **Figure 3.15** show PPG strength measurements for both brine concentration and size effects.

Figure 3.14 shows that PPG strength increased as NaCl concentration increased and also shows that gel particles swollen in formation water had almost the same gel strength.

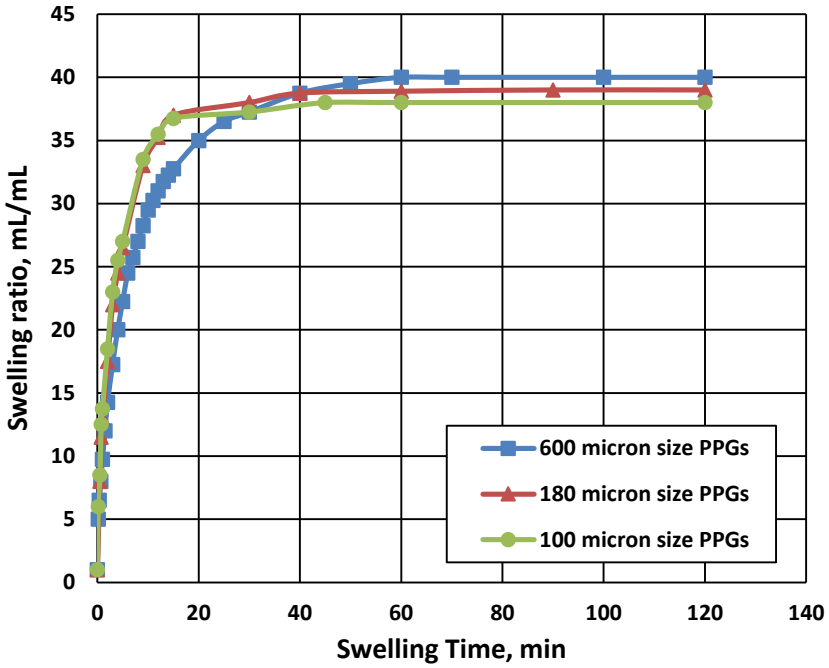


Figure 3.13 Swelling ratios measurements for different PPG sizes.

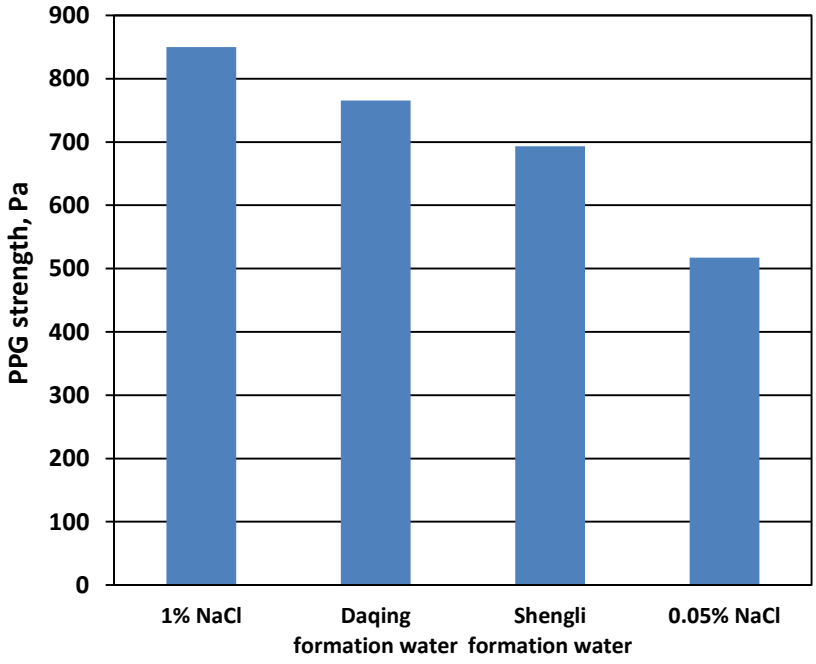


Figure 3.14. PPG strength measurement in different brine solutions.

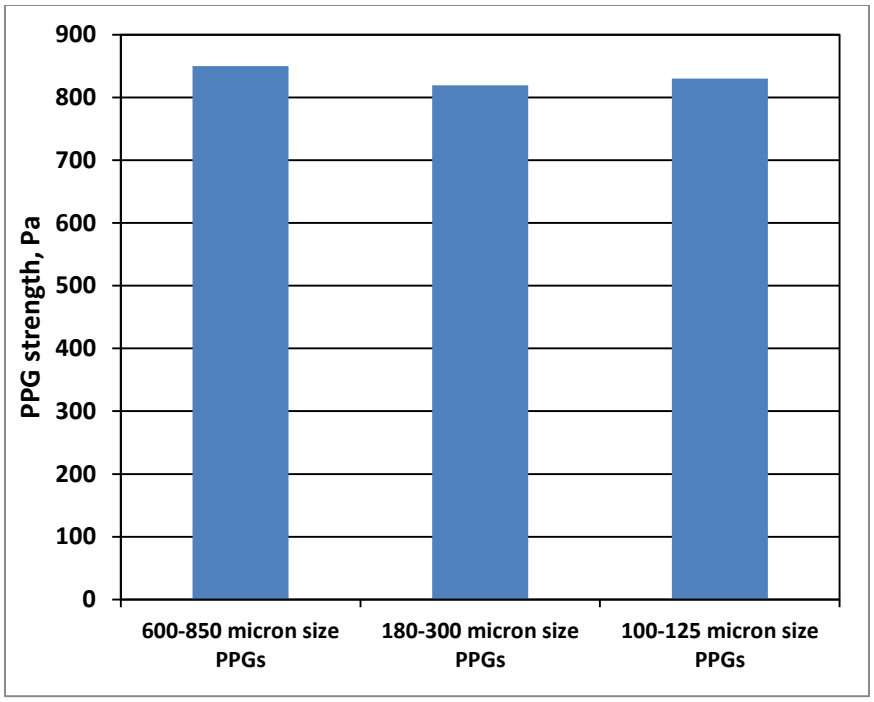


Figure 3.15. PPG strength measurements for different PPG sizes.

Figure 3.15 shows PPG strengths measured for different PPG sizes were almost equal. Gel strength results were consistent with swelling ratio results, which leads to the conclusion that gel strength was the main factor and should be considered in PPG injection design as more important than brine composition or gel particle sizes.

Swelling ratio and gel strength results obtained for PPG swollen in Daqing and Shengli formation water were very similar which explains why PPG threshold pressure, PPG stable pressure, and injection pore volume obtained for both formation water were not significantly affected by changing formation water. Therefore, both core flooding results and PPGs rheology measurements indicated that gel strength is more important than both PPG size and brine composition. PPGs strength should be highly considered during gel injection design, it will assist in predicting injection pressures for future projects.

3.3.2. Single-fracture Heterogeneous Model Results. Since fracture geometry is not expected to be uniform within a reservoir, experiments were designed to consider fracture width heterogeneity on PPG injection design. The following results discuss the effect of heterogeneity on both PPG injection and blocking behavior mechanism.

3.3.2.1 Effect of fracture heterogeneity on PPG injection. Figure 3.16 shows injection pressure measurements of 600-micron sized PPG swollen in 1% NaCl injected into the first heterogeneous fracture design model, in which the last 3 feet tube was replaced by smaller diameter tube. PPG injection pressure was plotted as a function of PPG injection pore volume. Injection pressure across fractures increased sharply after a few pore volume injections were made. Injection pressure started to rise at sensors P1, P2, and P3 at 5 PV, 6 PV, and 9 PV, respectively. Injection pressure readings recorded at P1 and P2 were very similar, while injection pressure readings recorded at sensor P3 had a large pressure drop with the first two sensors. Injection pressure at P1, P2, and P3 became stable at 1570 psi, 1520 psi, and 450 psi, respectively.

Pressure drop readings across sections were not equal; this was caused by the "choke" across the fracture. Some particle gels were accumulated in the choke point where fracture width changed and caused injection pressure (at P1 and P2) to increase sharply at that point. The other particle gels flew through this choke and caused injection pressure (at P3) to increase in the remaining fracture length.

Additional experiments were performed to understand the effect of heterogeneity and choke points on PPG injection pressure.

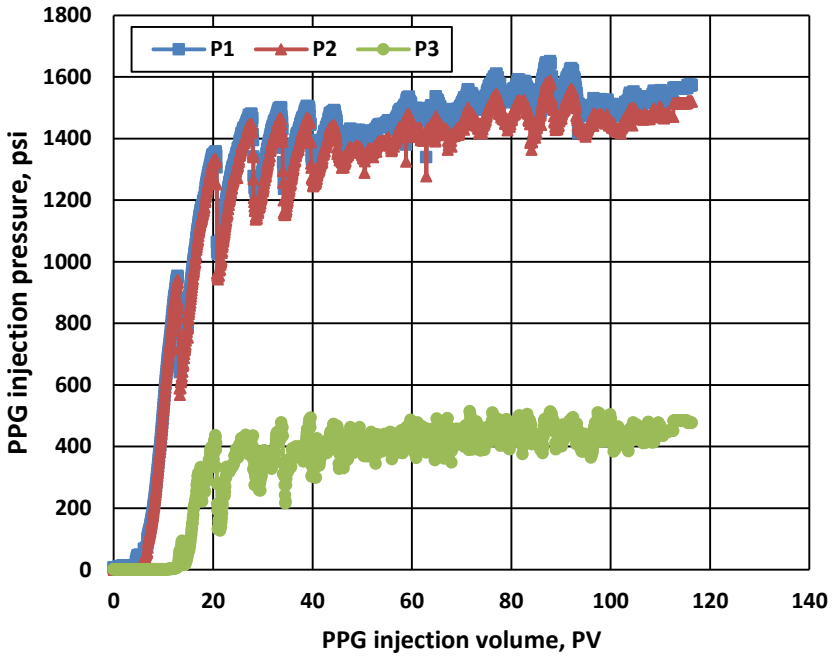


Figure 3.16. PPG injection pressure in heterogeneous fracture model [second model (first design), 600-850 micron, 1% NaCl, 1ml/min].

Figure 3.17 shows injection pressure measurements of 600-850 micron size PPG swollen in 1% NaCl injected into the second heterogeneous fracture design model, in which the middle two feet tube was replaced by tubes with smaller diameter. PPG injection pressure was plotted as a function of PPG injection pore volume. After injecting 25 PV PPG, injection pressure readings recorded at P1 and P2 increased at the same time, and stabilized at 1369 psi and 1261 psi. Injection pressure at P3 had large gaps with pressures at P1 and P2, stabilizing at 50 psi.

It could be easily observed that pressures at P3 for first and second design are different. The pressure in first design is much higher. This is because that changing the last three feet means the sections before and after P3 were all diameter decreased. Gel particles met more resistance when transporting in smaller diameter fractures.

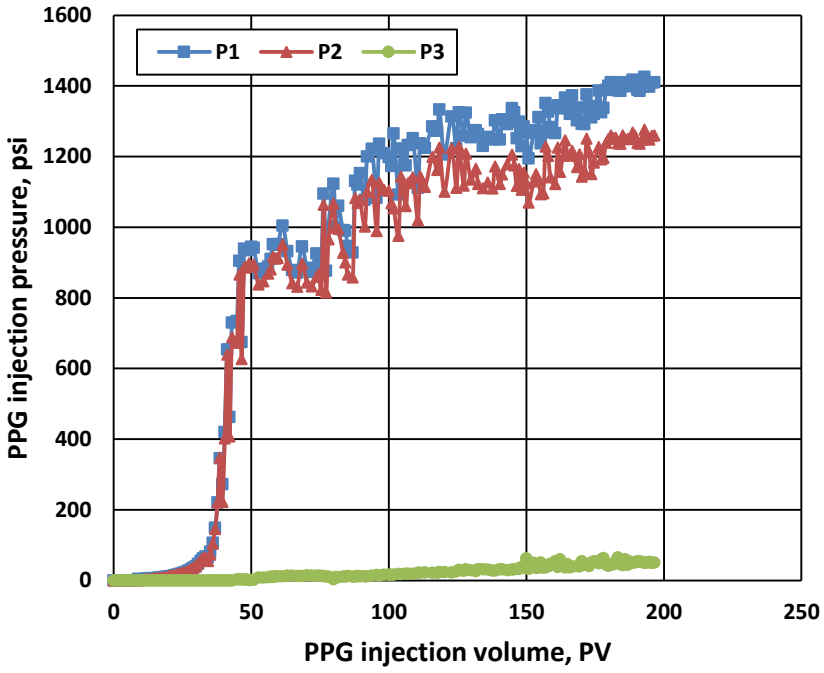


Figure 3.17. PPG injection pressure in heterogeneous fracture model [second model (second design), 600-850 micron, 1% NaCl, 1ml/min].

Being similar to the first heterogeneous model, pressures at P1 and P2 were very parallel. The pressure drop readings across sections were not equal. These results can still be explained as the effect of choke point. P1 and P2 were mounted before the choke point for both of the two experiments. The issue about choke point was further tested in another experiment using the third heterogeneous design model.

Figure 3.18 shows injection pressure measurements of 600-850 micron size PPG swollen in 1% NaCl injected into the third heterogeneous fracture design model, in which the last one foot tube was replaced by tubes with smaller diameter. PPG injection pressure was plotted as a function of PPG injection pore volume. After PPG injection for 25 pore volume, injection pressure readings at all sensors started to increase at the same time and stabilized at 916 psi, 793 psi and 680 psi, respectively.

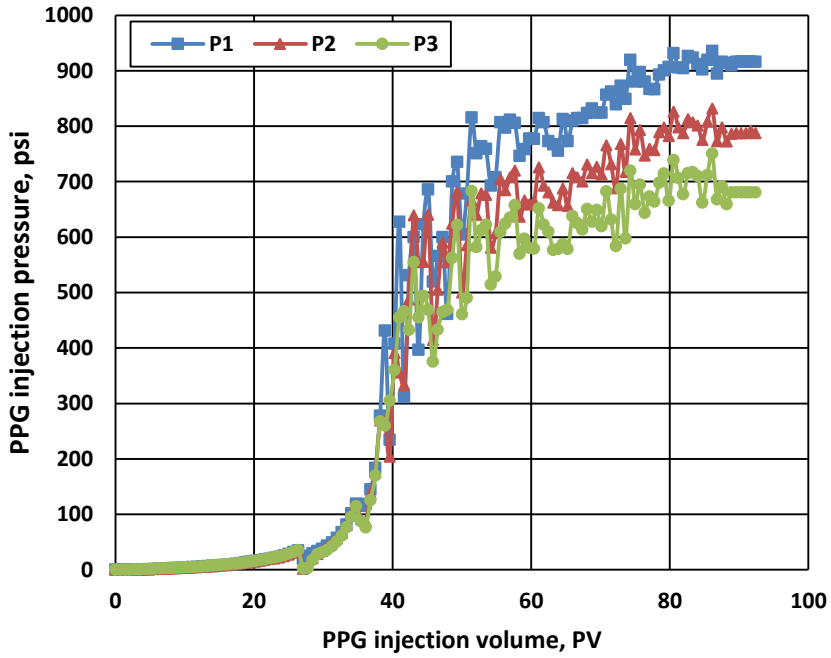


Figure 3.18. PPG injection pressure in heterogeneous fracture model [second model (third design), 600-850 micron, 1% NaCl, 1ml/min].

All the pressure curves measured by P1, P2 and P3 are paralleled, moreover, the pressure drops between them are the same. This happened because that the choke point turned to be at the downstream of all the sensors. Since the stable pressures is much larger than the pressure monitored in homogenous model, the effect of choke point becomes clearer: creating a significant pressure drop at its position.

Table 3.7 summaries the PPG injection stable pressure recorded from the uniform fracture model experiment and compared those results with the results from the fracture heterogeneous width model experiments. PPG injection stable pressure increased across the fracture as the heterogeneity fracture section increased. Stable injection pressure recorded at uniform fracture width was 305 psi and increased to 916.6 psi and 1570 psi when PPG was injected through the Third and First Design Models, respectively. Results also show pressure drops across fractures was slightly the same when fracture widths

were uniform. However, when fracture widths were not uniform along the fracture model, pressure drops differed. The difference in pressure drop was caused by the location of the choke point across the fracture. In a uniform fracture model, the pressure drop between P1 and P2 sensors was approximately 100 psi which was approximately the same pressure drop as that recorded between P2 and P3 sensors. In contrast, in fracture heterogeneity first design, the pressure drop between P1 and P2 sensors was approximately 50 psi, and it was approximately 1000 psi between P2 and P3 sensors.

Table 3.7. Effect of fracture width heterogeneity on PPG stable injection pressure.

Fracture Model		PPG stable pressure, psi		
		P1	P2	P3
Uniform fracture		305	186	77.5
Heterogeneity fracture	First design	1570	1520	450
	Second design	1369.7	1261	49.7
	Third design	916.6	793	680.7

Effect of injection flow rate. For all the fracture heterogeneity models, PPG injections were continued but with different velocities to determine the effect of heterogeneity on PPG injection pressure measurements.

Fig 3.19 shows PPG stable injection pressure at sensor P1 during PPG injection through uniform and heterogeneity fracture design models as a function of PPG injection velocity.

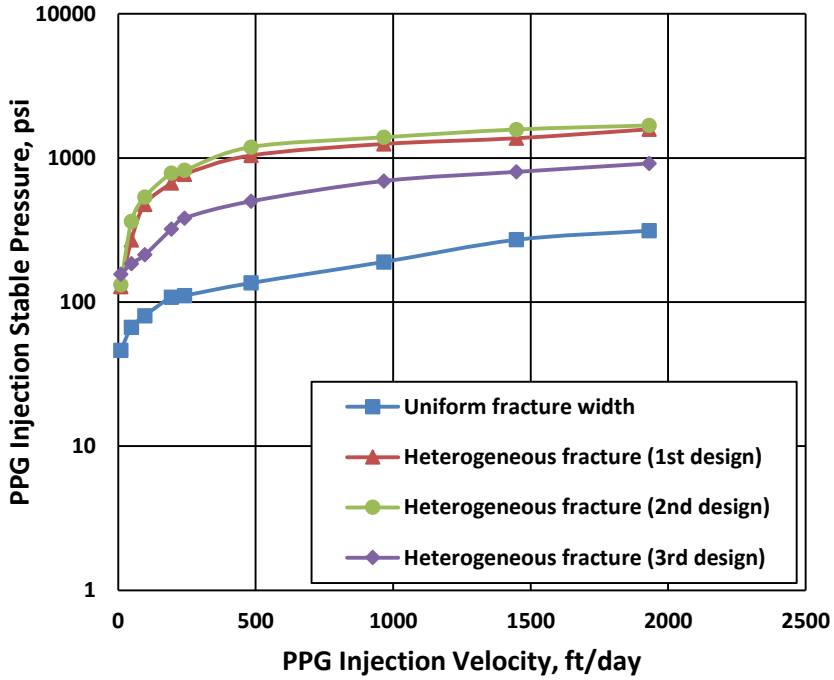


Figure 3.19. PPG injection pressure as a function of PPG injection velocity for different fracture models.

During all the PPG injection velocities, PPG injection pressures increased as the heterogeneity section within fractures increased. Interestingly, PPG injection stabilized pressure readings recorded for heterogeneity first and second designs, had very similar readings throughout all the PPG injections at different velocities. This behavior could be explained because of the choke point location for both models. Fracture Designs # 1 & 2 had the same choke location point (beginning of Section 2) which caused the pressure readings to be close to each other. Results also show that heterogeneity did not change

the fact that PPG injection pressure did not increase linearly with increased PPG injection velocity.

Additional experiments for effect of PPG size using heterogeneous model. Experiments were conducted using single-fracture heterogeneous model, to confirm the results gotten for effect of PPG size and brine concentration for preparing PPG.

Figure 3.20 shows injection pressure measurements of 100-125 micron size PPG swollen in 1% NaCl injected into the first heterogeneous fracture design model, in which the last 3 feet tube was changed into tubes with smaller diameters. The curve shows the relation between PPG injection pressure and PPG injection pore volume.

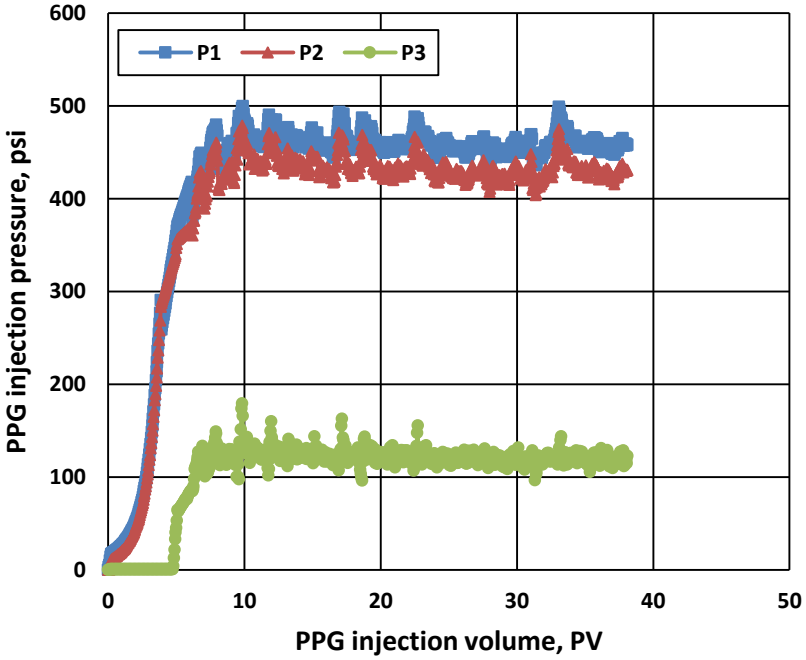


Figure 3.20. PPG injection pressure in heterogeneous fracture model [second model (first design), 100-125 micron, 1% NaCl, 1ml/min].

The pressure at sensors P1, P2 and P3 stabilized at 460 psi, 430 psi and 117 psi. Comparing with the stable pressures indicated in **Figure 3.16**, the conclusion that with

decreasing of PPG size, injection stable pressure will decrease is approved. Injection pressure measured by P1 and P2 increased at the beginning of injection, which is different with the phenomenon showed in **Figure 3.16**. This trade is the same as what happened for 100-125 micron size PPG propagation in homogeneous model, and also can be explained as the effect of low threshold pressure.

The pressure drop between P2 and P3 is 313 psi for 100-125 micron size PPG and more than 1000 psi for 600-850 micron size PPG. This result shows that pressure drop created by choke point will decrease with the declining of PPG size, which can be explained as smaller size PPG having a smaller threshold pressure for the choke point and following fractures.

Additional experiments for effect of brine concentration using heterogeneous model. **Figure 3.21** shows injection pressure measurements of 600-850 micron size PPG swollen in 0.05% NaCl injected into the first heterogeneous fracture design model, in which the last 3 feet tube was changed into tubes with smaller diameters. The curve shows the relation between PPG injection pressure and PPG injection pore volume.

The pressure monitored by P1 and P2 started to increase significantly after injection for 14 PV. The pressure at sensors P1, P2 and P3 stabilized at 954 psi, 882 psi and 382 psi, which are all much lower than the pressure measured for 1% NaCl in **Figure 3.16**. This result confirms the conclusion that PPG propagation stable pressure is lower for PPG prepared in brine with lower concentration.

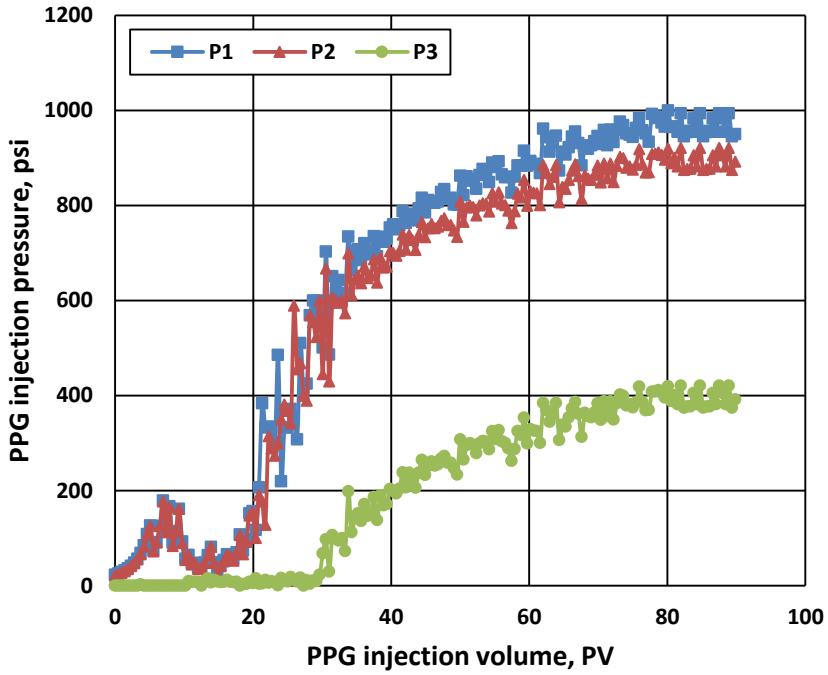
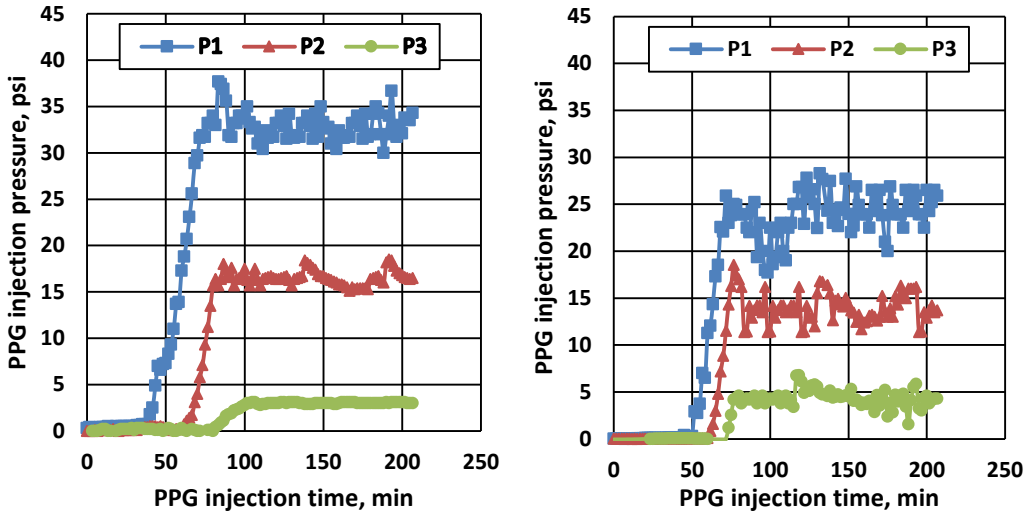


Figure 3.21. PPG injection pressure in heterogeneous model
[second model (first design), 600-850 micron size PPG, 0.05% NaCl, 1ml/min].

The pressure drop between P2 and P3 for PPG swollen in 0.05% NaCl is 500 psi, which is much lower than the pressure drop measured for 1% NaCl. This result shows the pressure drop created by choke point will decline as the brine concentration decreasing. Being similar to effect of PPG size, the conclusion about pressure drop can be also explained as declining of threshold pressure for lower brine concentration prepared PPG.

3.3.1. Parallel-fracture Model Result. PPG was used successfully to correct the non-cross flow heterogeneity formations (Imqam et al. 2015b and d). PPG flowed more deeply into high permeability than it did into low permeability. However, the criteria which controlled this flow still need more investigation. In this study, different models of non-cross flow heterogeneity fractures were designed to assist in understanding the behavior of PPG injection through these features.

Figure 3.22 depicts the PPG injection pressure measured from injecting PPG swollen in 1% NaCl through parallel fracture experiment model #1 with a fracture width ratio of 1.739. **Figure 3.22a** and **b** show PPG injection pressure plotted as a function of PPG production pore volume (PV). The production volume presents the PPG volume produced from the fracture that is monitored. The pore volume was calculated using the inner volume of the specified fracture.



a) Fracture width of 1.752 mm b) Fracture width of 3.048 mm

Figure 3.22. PPG injection pressure through fracture width ratio of 1.739 using PPG swollen in 1% NaCl solution.

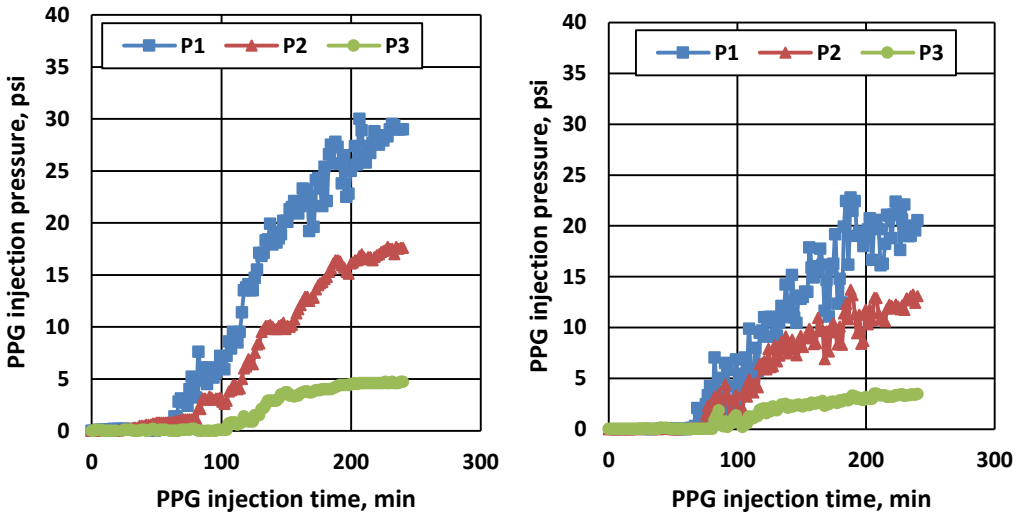
In a fracture width of 1.752 mm, PPG injection pressure at P1, P2 and P3 doesn't increased as PPG produced from the outlet, until 0.20 PV, 0.3 PV and 0.43 PV. According to the experimental phenomenon records, the effluent in these periods was mostly brine created by concentration and dehydration of gel particles, which created extremely low pressure that cannot be detected by the sensors. After these time periods, injection pressure started grow sharply across the model and stabilized at 33.2 psi, 16.5

psi and 5.1 psi for P1, P2 and P3 of 1.752 mm-width fracture, respectively. For the 3.048 mm-width fracture, pressure stabilized at 24.3 psi, 13.5 psi, 4.2 psi at P1, P2 and P3, respectively. The injection pressure drop measured across these sensors indicate that PPG symmetrically reduced/blocked the permeability of both of the fractures. The injection pressure and PPG production volume recorded from these two fractures indicated that PPG flowed through both of the fractures.

Moreover, produced PPG volume was measured. The experimental records showed 87.42% of the effluent was produced from fracture with larger width, 3.048 mm and 2.65% produced from the fracture with smaller size. This result shows that for parallel fractures with different width, more volume of PPG and brine flow through the fracture with larger width. This conclusion is confirmed in following experiments and results.

Figure 3.23 depicts the PPG injection pressure measured from injecting PPG swollen in 0.05% NaCl through parallel fracture experiment model #2 with a fracture width ratio of 1.739. **Figure 3.23a** and **b** show PPG injection pressure plotted as a function of PPG production pore volume (PV).

In the fracture with a width of 1.752 mm, PPG injection pressure at P1, P2 and P3 increased and stabilized at 29.0 psi, 15.6 psi and 3.7 psi, respectively. For the 3.048 mm-width fracture, pressure stabilized at 20.1 psi, 13.0 psi and 3.8 psi at sensors P1, P2 and P3. The injection pressure and PPG production volume recorded from these two fractures indicated that PPG flowed through both of the fractures.

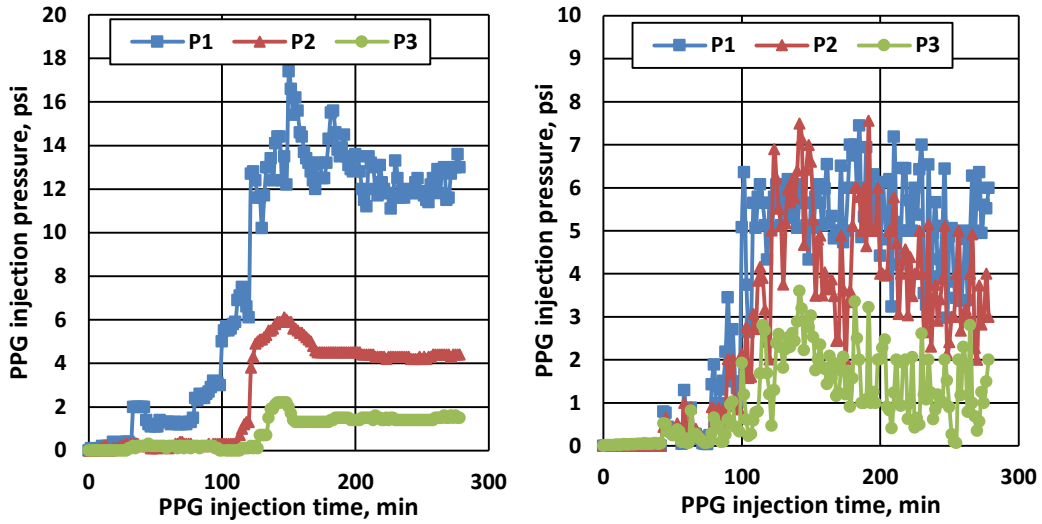


a) Fracture width of 1.752 mm b) Fracture width of 3.048 mm

Figure 3.23. PPG injection pressure through fracture width ratio of 1.739 using PPG swollen in 0.05% NaCl solution.

The experimental records showed 82.75% of the effluent was produced from fracture with width being 3.048 mm and 8.68% produced from the fracture with 1.752 mm width. Comparing with the result from parallel fracture experiment model #1, a larger percentage of PPG was produced from smaller-size fracture. This conclusion is confirmed by the following experiment.

Figure 3.24 shows the PPG injection pressure measured from injecting PPG swollen in 0.005% NaCl through parallel fracture experiment model #3 with a fracture width ratio of 1.739. **Figure 3.24a** and **b** show PPG injection pressure plotted as a function of PPG production pore volume (PV).



a) Fracture width of 1.752 mm b) Fracture width of 3.048 mm

Figure 3.24. PPG injection pressure through fracture width ratio of 1.739 using PPG swollen in 0.005% NaCl solution.

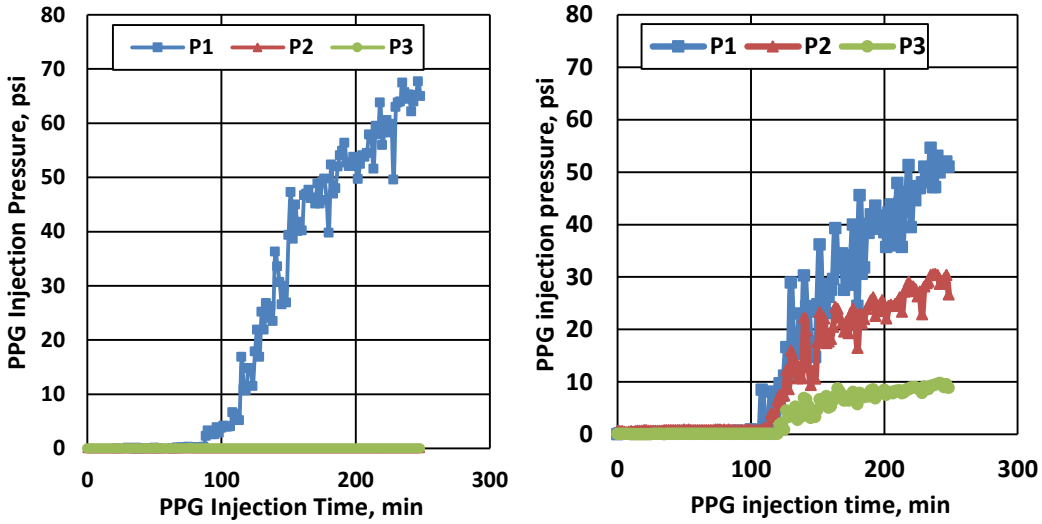
In the fracture with a width of 1.752 mm, PPG injection pressure at P1, P2 and P3 increased and stabilized at 12.7 psi, 5.9 psi and 1.5 psi, respectively. In the fracture with a width of 3.048 mm, pressure stabilized at 4.0 psi, 3.5 psi and 2.2 psi at sensors P1, P2 and P3. The injection pressure and PPG production volume recorded from these two fractures indicated that PPG flowed through both of the fractures.

The experimental records showed 82.59% of the effluent was produced from fracture with width being 3.048 mm and 9.67% produced from the fracture with 1.752 mm width. Comparing with the result from parallel fracture experiment model #1 and #2, a larger percentage of PPG was produced from smaller-size fracture for PPG with lower strength.

These three experiments above proved PPG swollen in different brine concentration propagating through parallel fractures with same fracture width ratio,

which is equal to 1.739. One experiment was run to investigate the effect of fracture width ratio on PPG propagation through parallel fractures.

Figure 3.25 shows the PPG injection pressure measured from injecting PPG swollen in 1% NaCl through heterogeneity models with a fracture width ratio of 3.937.



a) Fracture width of 0.774 mm b) Fracture width of 3.048 mm

Figure 3.25. PPG injection pressure through fracture width ratio of 3.937 using PPG swollen in 1% NaCl solution.

Figure 3.25a shows PPG injection pressure plotted as a function of PPG injection time, while **Figure 3.25b** shows PPG injection pressure plotted as a function of PPG production pore volume (PV). In a fracture width of 0.774 mm, PPG injection pressure increased only at the fracture inlet (P1). Injection pressures across the fracture showed that PPG only hit or accumulated at the fracture inlet and did not flow deep across the fracture. Also, we did not observe any produced particle gels at the effluent. In contrast, with a fracture width of 3.048 mm, PPG injection pressure increased across the fracture model. Injection pressure at P1, P2, and P3 was 50 psi, 30 psi, and 10 psi, respectively.

The injection pressure drop measured across these sensors indicate that PPG symmetrically reduced/blocked the permeability of this large fracture. The injection pressure and PPG production volume recorded from these two fractures indicated that PPG at this fracture width ratio only flowed through large fracture width. Little volume of particle gels accumulated at the fracture inlet but did not flow inside the fracture.

Table 3.8 provides a summary of injection stable pressure recorded across fractures for four parallel fracture models, which were separately discussed in the sections above.

Table 3.8. Effect of fracture width ratio and gel strength on PPG injection pressure across non-cross flow fractures.

Experiment model #	PPG strength, pa	Fracture width (mm)	Fracture width ratio	Ratio of Dg/Wf	PPG injection stable pressure, psi		
					P1	P2	P3
1	850	1.752	1.739	1.826	33.2	16.5	5.1
		3.048		1.050	24.3	13.5	4.2
2	517	1.752	1.739	2.785	29.0	15.6	3.7
		3.048		1.601	20.1	13.0	3.8
3	360	1.752	1.739	3.344	12.7	5.9	1.5
		3.048		1.923	4.0	3.5	2.2
4	850	0.774	3.937	4.134	65	0	0
		3.048		1.050	51.3	29.3	9.0

Experiment Model # 1 and 4 were for PPG with the same strength and size but which were injected into two different fracture width ratios. Injection pressure measurements across fracture Model # 1, shows that PPG was propagated into whole fracture length for both large and small fracture widths. In contrast, when large fracture width was approximately four times bigger than a small fracture width (Model # 4), injection pressure measurements across fractures showed that PPG only flowed into large fracture widths.

Results obtained from Models #1, 2, and 3 indicated that as PPG strength reduced, gel injection pressure across small fracture width decreased and allow more gel particles to flow deep into small fracture widths. PPG with a strength of 850 pa had an injection stable pressure of 33.2 psi, 16.5 psi, and 5.1 psi along the small fracture width of 1.752 mm. When PPG strength decreased to 360 pa, injection stable pressure across small fractures of 1.752 mm became 12.7 psi, 5.9 psi, and 1.5 psi.

Threshold pressure and PPG volume production at effluents are both recorded and summarized in **Table 3.9**. As what is expected, based on gel strength and fracture width ratio, large fracture width required less threshold pressure for PPG to flow than smaller fracture width. Results obtained from experiment Models # 1, 2, and 3 showed a stronger PPG required higher injection pressure to initiate PPG into fractures than a weaker PPG. Additionally, if the fracture width ratio increased to approximately four (Model #4), the threshold pressure required for the PPG strength of 850 pa to flow into a smaller fracture width increased by approximately eight times over the fracture width ratio of two (Model #1).

Table 3.9. Effect of fracture width ratio and gel strength on PPG flow through non-cross flow fractures.

Experiment model #	PPG strength, pa	Fracture width (mm)	Fracture width ratio	Threshold pressure, psi	PPG injection and Production volume		
					PPG Injected (ml)	PPG Produced (ml)	Produced volume percentage %
1	850	1.752	1.739	7	151	4	2.65
		3.048		3.8		132	87.42
2	517	1.752	1.739	4.5	172.8	15	8.68
		3.048		2.0		143	82.75
3	360	1.752	1.739	3.4	191.3	18.5	9.67
		3.048		0.8		158	82.59
4	850	0.774	3.937	54.9	184.9	0	0
		3.048		3.9		180	97.35

Particle gel volume collected at effluents showed a low percentage of PPG volume flowing into smaller fracture widths when a stronger PPG was selected. PPG production volume collected from smaller fracture widths for Models #1, 2 and 3 were 2.65%, 8.68%, and 9.67%, respectively. When fracture width ratios increased (Model #4), all the PPG injection volumes flowed only through large fracture widths (3.048 mm,

which explains why the pressure reading (**Figure 3.25a**) did not change across the fracture width of 0.774 mm).

PPG threshold pressure, injection stable pressure, and production volume percentage results conclude that PPG strength and fracture width ratio are very important parameters control PPG injection through non-cross flow heterogeneity fracture. Results also conclude that PPG strength of 850 pa and above would not propagate into smaller fracture width if the fracture width ratio were approximately four and above.

3.4. RESULT AND ANALYSIS OF PPG RESISTENCE TO WATER FLOW

Besides PPG injectivity, the ability of resisting to water flow is another crucial factor. To prove the mechanisms of PPG resistance to water flow in heterogeneous fractures, after PPG injection was complete, different cycles of brine solutions were injected into fractures at a low velocity of 48 ft. /day to determine PPG resistance to brine flow.

Figure 3.26 shows injection pressure measurements across fractures as a result of injecting brine solution of 1% NaCl through swollen PPG. The 600-850 micron size PPG was swollen in 1% NaCl. As the brine injection volume increased, brine injection pressure increased until it reached approximately 90 psi and then declined. The drop in pressure after reaching 90 psi was because of brine breakthrough at the fracture outlet. Some gel particles were produced during this injection and some were left behind within the fracture and creating resistance to water flow. Brine solution injections continued until injection pressures became stable along fractures and only brine flowed from

fractures. The brine injection stable pressure, which is 12 psi was still higher than the stable injection pressure of brine before PPG injection.

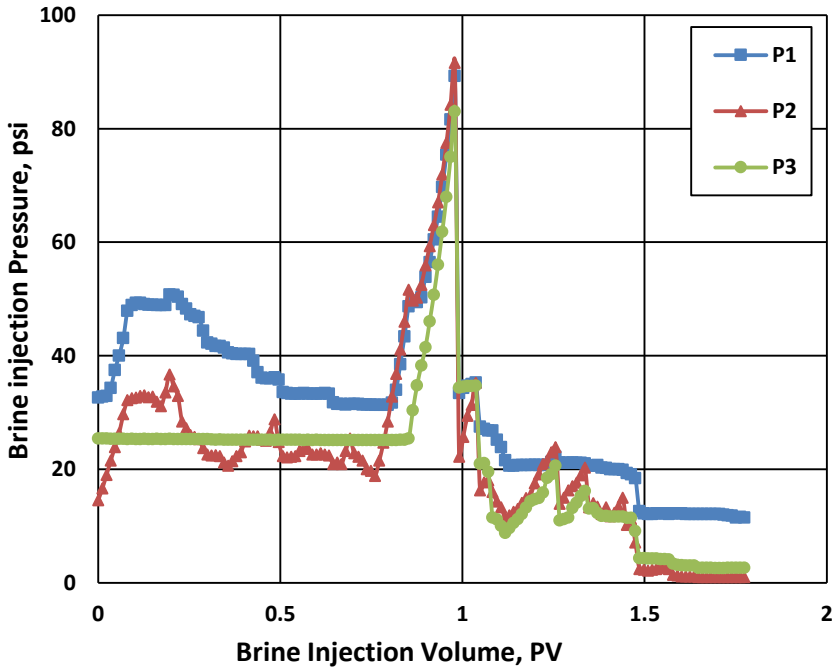


Figure 3.26. Injection pressure measurements of injected 1% NaCl through 600-850 micron size PPG swollen in 1% NaCl.

Additional research was conducted to better understand factors affecting PPG resistance to water flow. These factors include PPG size, PPG strength and changes in water salinity.

Effect of PPG size. **Figure 3.27** and **Figure 3.28** show injection pressure measurements across fractures as a result of injecting brine solution of 1% NaCl through swollen 180-300 and 100-125 micron size PPG. As the brine injection volume increased, brine broke through at approximately 30 psi for 180-300 micron size PPG, 4.5 psi for 100-125 micron size and then declined. Brine solution injections continued until injection

pressures became stable along fractures and only brine flowed from fractures. The stable pressure at P1 is approximately 3.0 psi and 0.72 psi, which is lower than 12 psi from 600-850 micron size PPG experiment.

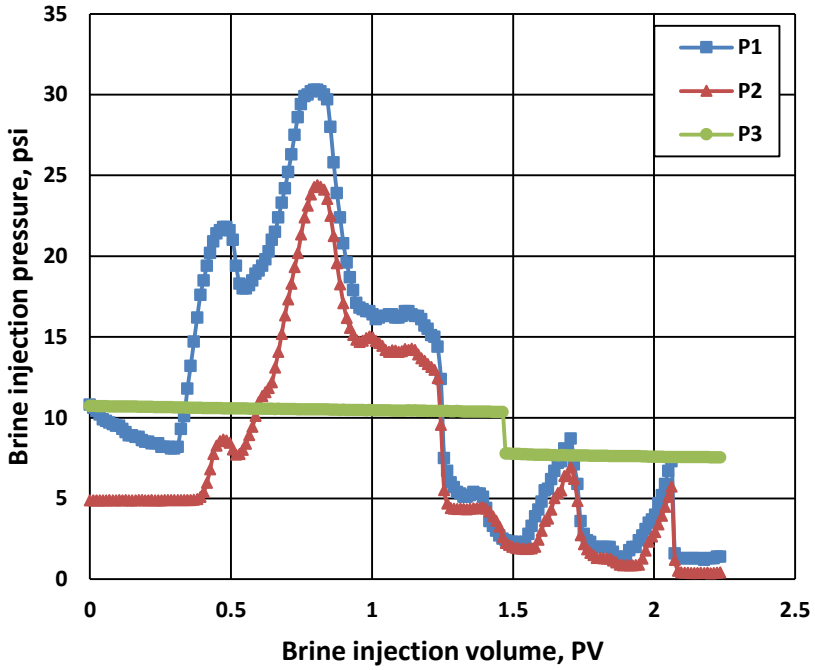


Figure 3.27. Injection pressure measurements of injected 1% NaCl through 180-300 micron size PPG swollen in 1% NaCl.

Interestingly, from both of the figures, stable pressure at P3 was higher than stable pressure at P1 or both of P1, P2. This happens probably because some gel particles stack on the tube walls, which connect fracture model and pressure sensors, brine injection flow rate is too low to remove this kind of PPG. This portion of PPG created an extra pressure and disabled the sensor P3 to monitor brine injection pressure accurately.

Table 3.10 summarizes the results for three PPG sizes swollen in the same 1% NaCl concentration.

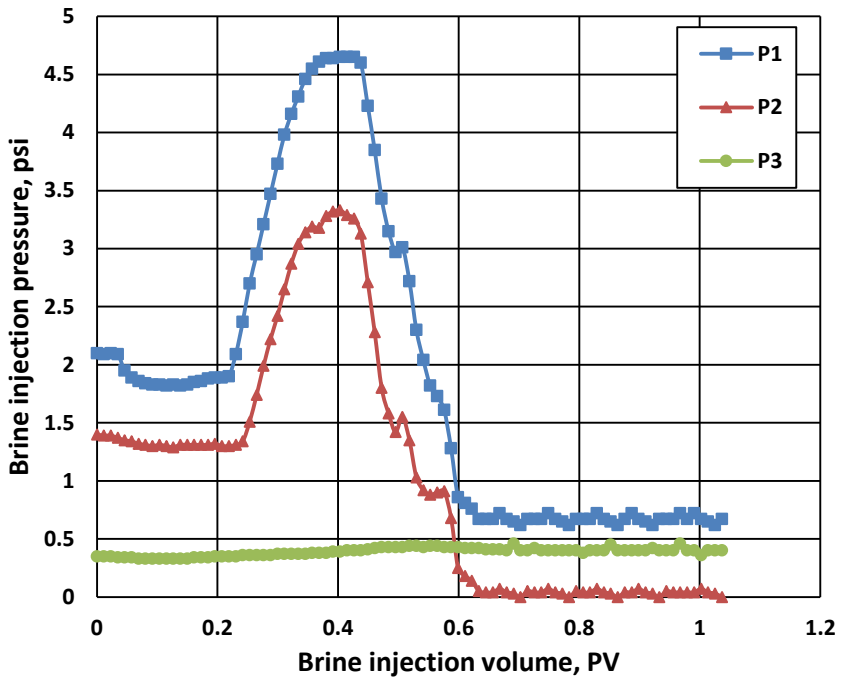


Figure 3.28. Injection pressure measurements of injected 1% NaCl through 100-125 micron size PPG swollen in 1% NaCl.

Table 3.10. Effect of PPG size on blocking efficiency of water flow in uniform fracture width of 1.752 mm.

Effects		PPG stable pressure, psi	Brine breakthrough pressure, psi	Brine stable pressure, psi	Brine breakthrough volume, PV	PPG blocking Efficiency, %
PPG size, micron	600-850	305	89.3	12.2	1.0	99.8
	180-300	142	29.8	3.0	0.75	99.5
	100-125	37	4.55	0.67	0.36	98.1

Brine breakthrough pressure readings show that PPG resistance to water flow increased as PPG size increased. Brine breakthrough pressures were 89.3 psi, 29.8 psi, and 4.55 psi with PPG sizes of 600-850 microns, 180-300 microns, and 100-125 microns, respectively. Results also indicated that large PPG size can resist large injection volumes of brine from the being produced through fractures. PPG blocking efficiency results suggest that PPG can provide a 98% and above blocking efficiency to water flow.

Effect of PPG strength.

Figure 3.29, Figure 3.30 and **Figure 3.31** show injection pressure measurements across fractures as a result of injecting brine solution of the solution, which is used to swell PPG, through placed PPG. As the brine injection volume increased, brine injection pressure increased until its breakthrough PV and breakthrough pressure and then declined. The experimental records showed a portion of PPG was produced during this injection and some were left behind within the fracture and creating resistance to water flow. Brine solution injections continued until injection pressures became stable along fractures and only brine flowed from fractures.

Table 3.11 summarizes the results for four PPG strengths had the same PPG particle size of 600-850 microns.

Brine breakthrough pressure readings show that PPG resistance to water flow increased as gel strength increased. When PPG strength decreased from 850 pa to 517 pa, the brine breakthrough pressure decreased from 89.3 psi to 15.2 psi.

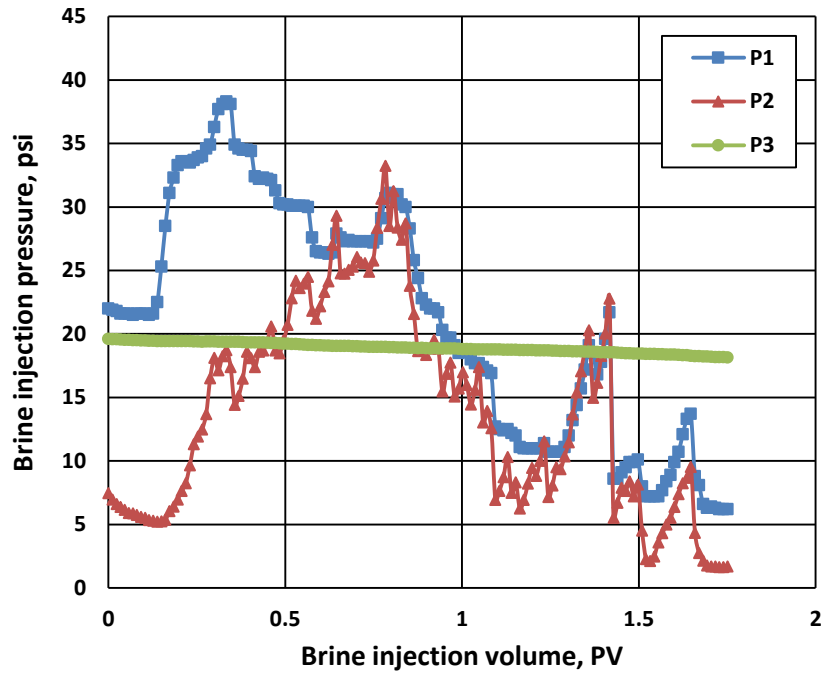


Figure 3.29. Injection pressure measurements of injected Shengli formation water through 600-850 micron size PPG swollen in Shengli formation water.

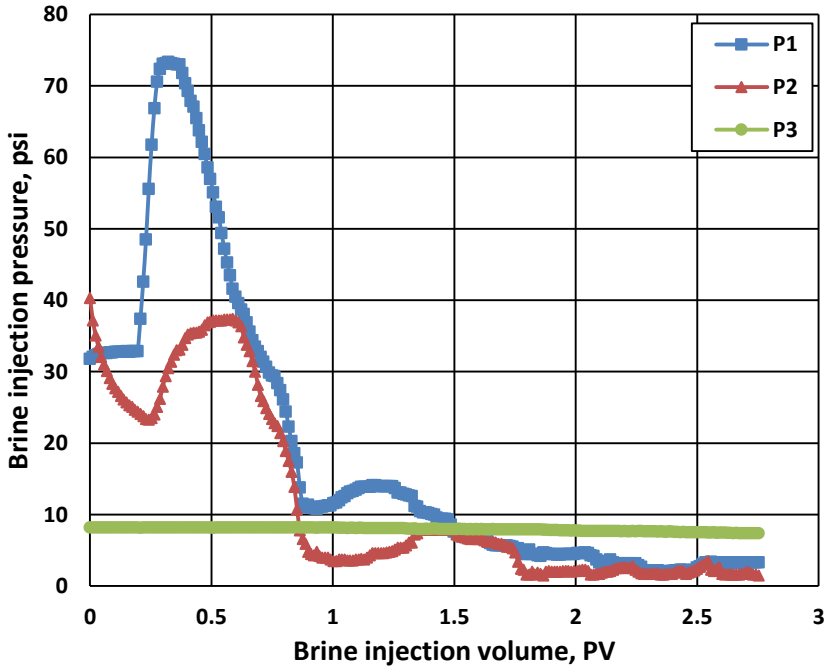


Figure 3.30. Injection pressure measurements of injected Daqing formation water through 600-850 micron size PPG swollen in Daqing formation water.

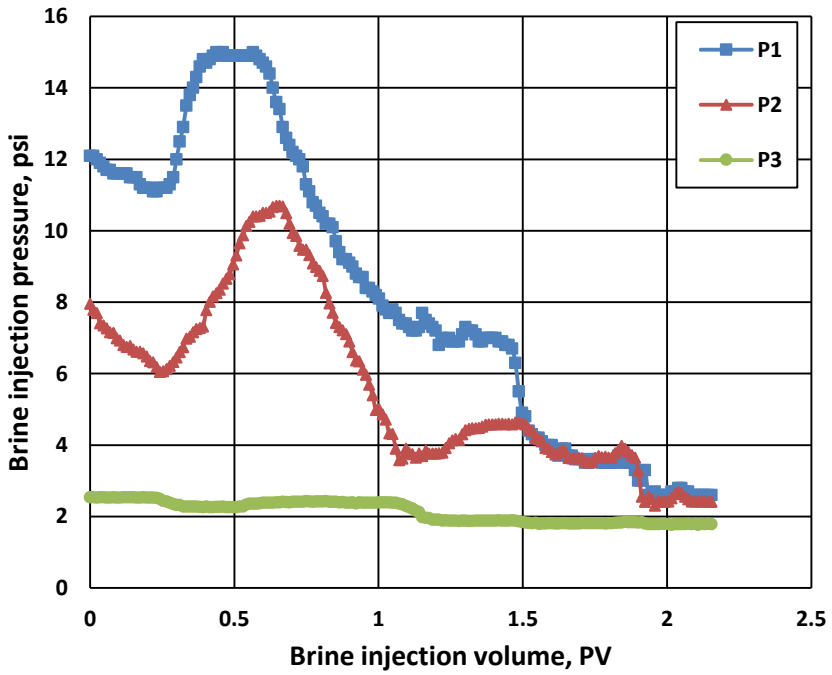


Figure 3.31. Injection pressure measurements of injected 0.05% NaCl through 600-850 micron size PPG swollen in 0.05% NaCl.

Table 3.11. Effect of brine concentration on blocking efficiency of water flow in uniform fracture width of 1.752 mm.

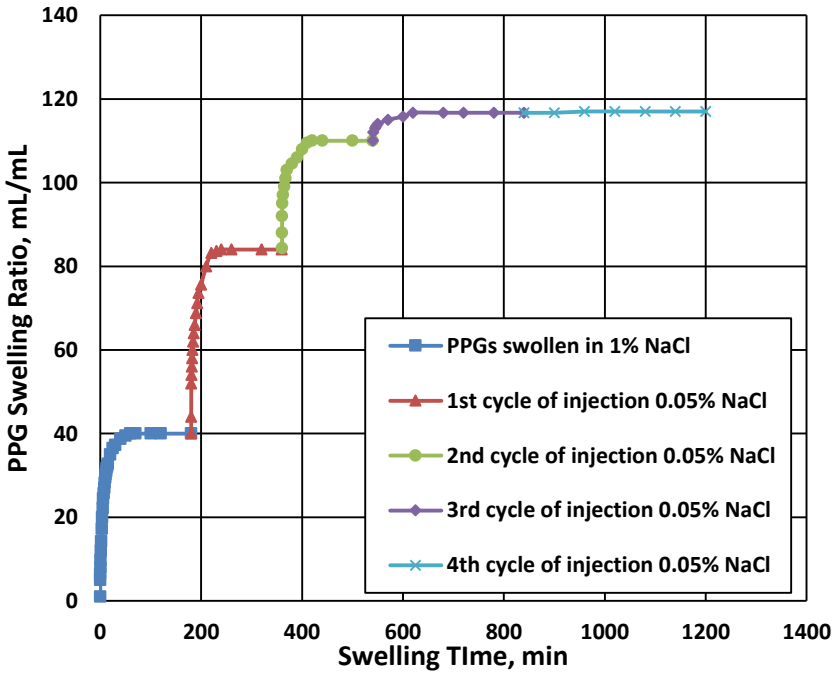
Effects		PPG stable pressure, psi	Brine breakthrough pressure, psi	Brine stable pressure, psi	Brine breakthrough volume, PV	PPG blocking Efficiency, %
PPG strengths, pa	850	305	89.3	12.2	1.0	99.8
	693	296	75.1	5.2	0.38	99.7
	765	289	72.4	3.3	0.37	99.6
	517	131	15.2	2.6	0.32	99.5

Results also indicated that high gel strength will create resistance to large injection volumes of brine from the propagating through fractures. Again, PPG blocking efficiency results suggest that PPG can provide a 98% and above blocking efficiency to water flow.

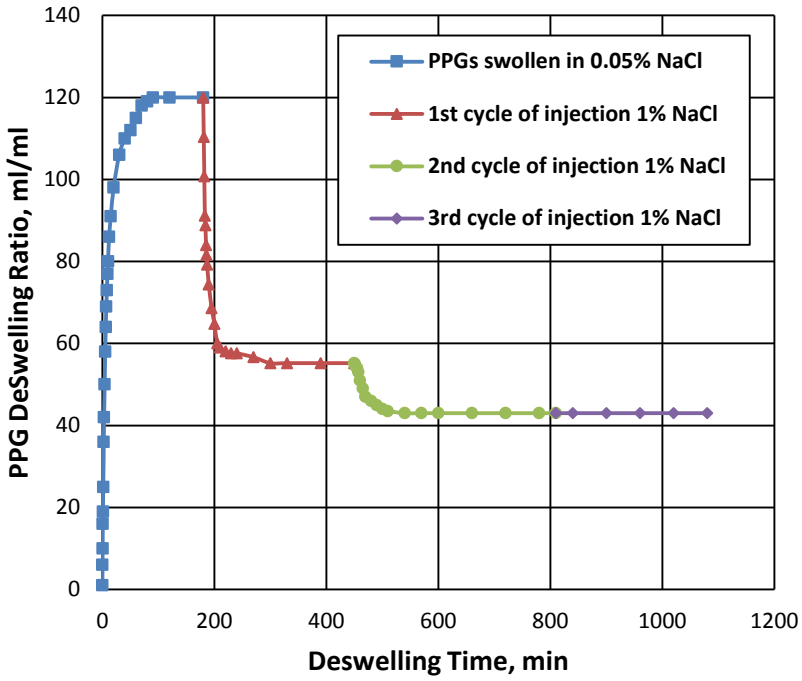
These results show that PPG resistance to water flow through fractures can be more efficient if large particle sizes and high gel strength PPG are selected for treatment.

Effect of changes in water salinity. In a reservoir situation, formation water might not have the same salinity concentration with PPG. Hence, it is essential to understand how the PPG swelling ratio change will influence PPG effectiveness to reduce water flow.

Figure 3.32a shows fully swollen PPG in 1% NaCl flushed with different cycles of 0.05% NaCl.



a) Swelling ration for decreased water salinity



b) De-swelling ration for increased water salinity

Figure 3.32. Swelling ratio measurement when salinity increased and decreased.

Figure 3.32b shows fully swollen PPG in 0.05% NaCl flushed with different cycles of 1% NaCl. Results indicate that the PPG swelling ratio did not return to its original swelling ratio until the swollen PPG was flushed with at least three cycles. Results obtained from **Figure 3.32a** show the PPG swelling ratio with a brine concentration of 1% NaCl to be 40; however, after the 0.05% NaCl brine concentration was flushed under the different cycles, the swelling ratio increased to 120, which is the original swelling ratio for PPG swelling in 0.05% NaCl. Results obtained from **Figure 3.32b**, show a different trend, where PPG started to shrink. As the brine concentration increased from 0.05 % NaCl to 1% NaCl, the deswelling ratio after cycles of 1% NaCl finally ended up at 40 which is the same swelling ratio for PPG swollen in a brine concentration of 1% NaCl. These results indicate that the PPG will finally accommodate

the swelling ratio of the formation water, but not the one it was swelled in or prepared with.

Additional investigations on the effect of changing water salinity were performed by using core flooding experiments. A second brine cycle was performed after the first brine injection cycle. The second cycle of 0.05% NaCl brine had salinity less than the previously injected brine solution.

Figure 3.33 to **Figure 3.38** show the brine injection pressure of 0.05% NaCl injected after completion of the first cycle of 1% NaCl. **Figure 3.33**, **Figure 3.34** and **Figure 3.35** shows no change in brine injection pressure when dealing with a uniform fracture width of 1.752 mm. Taking **Figure 3.33** as an example, brine injection pressure during the first cycle of 1% NaCl and the second cycle of 0.05% NaCl was still at approximately 10 psi.

Unexpectedly, **Figure 3.36**, **Figure 3.37** and **Figure 3.38** show injection pressure increased during the second cycle when single fracture heterogeneous models were used. In **Figure 3.36**, during the first cycle of 1% NaCl injection, brine injection pressure became stable at approximately 6 psi, but during the second cycle of 0.05% NaCl, the injection pressure increased and became stable at approximately 70 psi.

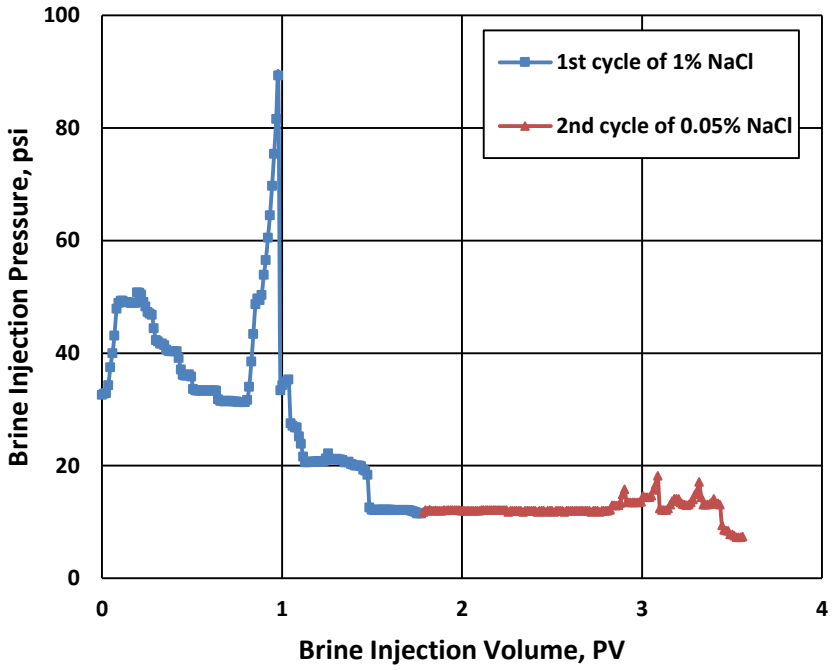


Figure 3.33. Brine Injection pressure for two brine cycles of 1% NaCl and 0.05% NaCl (Uniform 1.752 mm-width fracture, 600-850 micron size PPG).

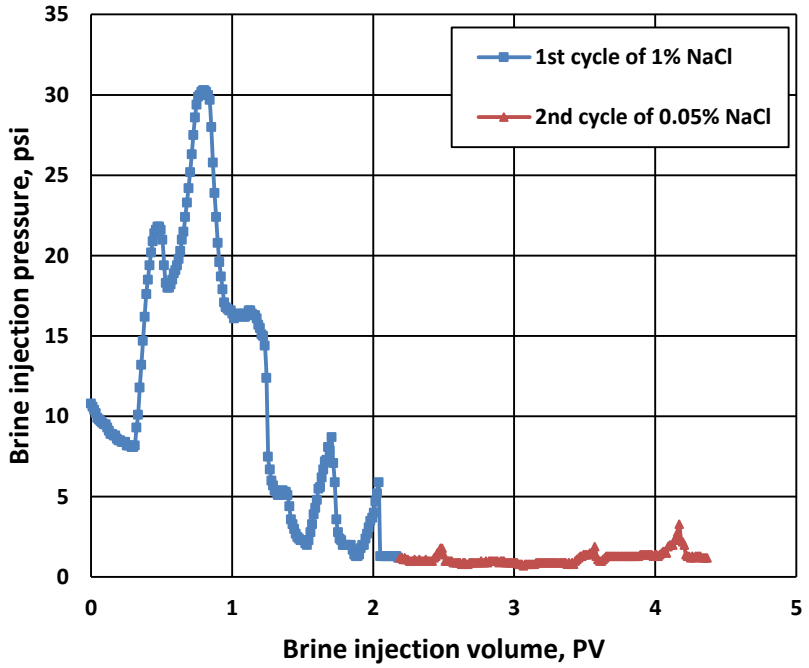


Figure 3.34. Brine Injection pressure for two brine cycles of 1% NaCl and 0.05% NaCl (Uniform 1.752 mm-width fracture, 180-300 micron size PPG).

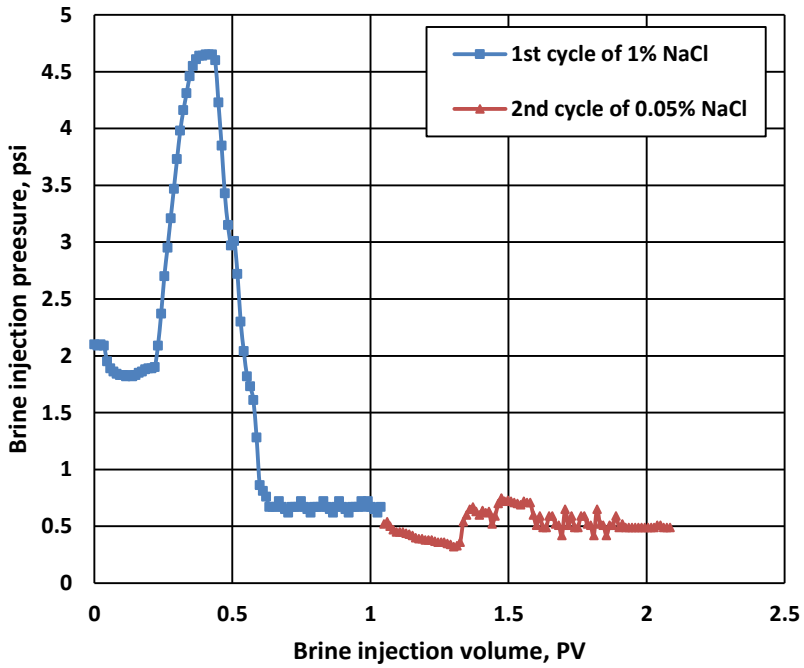


Figure 3.35. Brine Injection pressure for two brine cycles of 1% NaCl and 0.05% NaCl (Uniform 1.752 mm-width fracture, 100-125 micron size PPG).

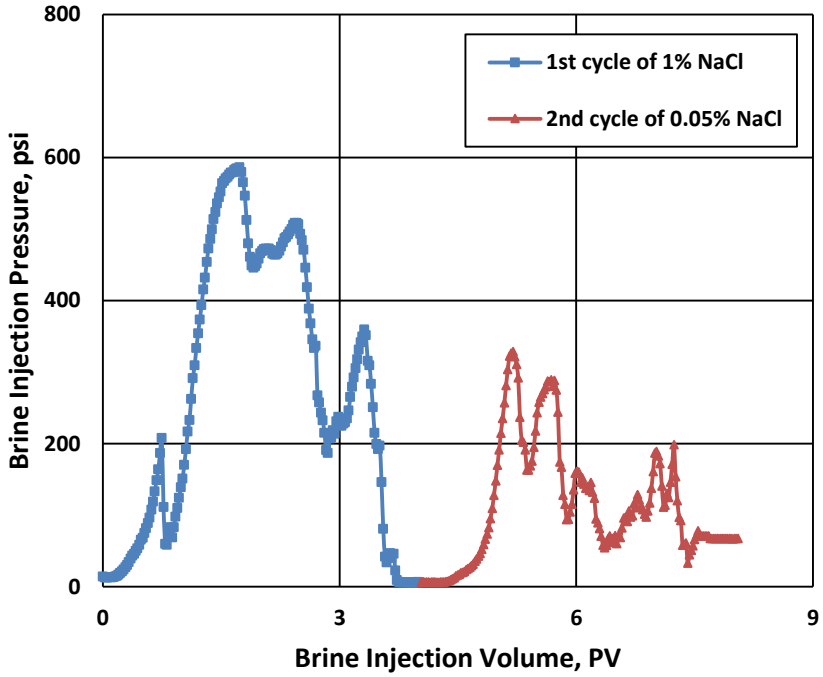


Figure 3.36. Brine Injection pressure for two brine cycles of 1% NaCl and 0.05% NaCl (Single fracture heterogeneous model 1st design, 600-850 micron size PPG).

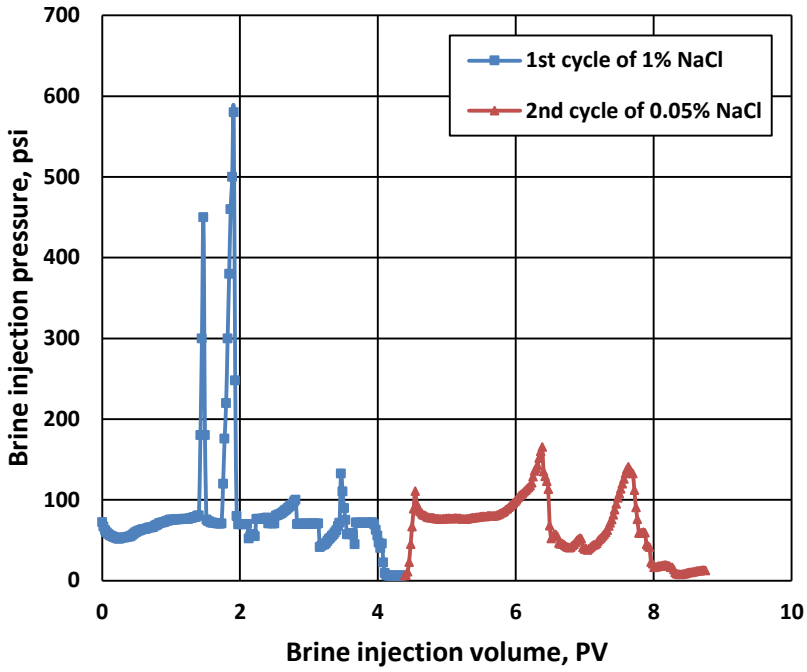


Figure 3.37. Brine Injection pressure for two brine cycles of 1% NaCl and 0.05% NaCl (Single fracture heterogeneous model 2st design, 600-850 micron size PPG).

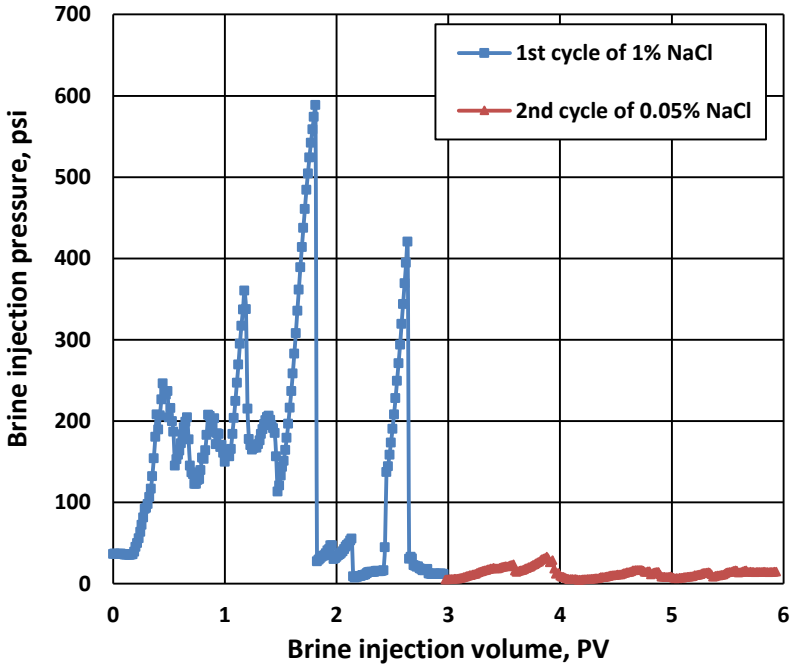


Figure 3.38. Brine Injection pressure for two brine cycles of 1% NaCl and 0.05% NaCl (Single fracture heterogeneous model 3rd design, 600-850 micron size PPG).

The results that stable pressure in 2nd cycle of brine injection was higher than the pressure in first cycle were also observed in **Figure 3.37** and **Figure 3.38**. Considering the heterogeneity within the reservoir, these results showed that water salinity within the reservoir could play a very important role in PPG capability to reduce water channeling if the brine concentration within the reservoir is less than the swollen PPG salinities. This phenomenon will be discussed in the following section.

3.5. DISCUSSION

In PPG injection field design, the formation of water salinity might differ from the water salinity used to swell gel. Referring to the results obtained from **Figure 3.36** to **Figure 3.38**, PPG resistance to water flow increases when the injected water salinity concentration is less than the water salinity concentration used to swell PPG. This kind of behavior led us to investigate some questions that might be responsible for this behavior. These questions follow:

- Was it only the change in water salinity that generated the test plan to increase injection pressure or was it a combination with fracture width geometry?
- Did the gel strength and swelling ratio contribute to the increased brine injection pressure?
- Could injection velocity eliminate this effect if injection velocity was increased?

To answer the first question, additional experiments were performed using both homogenous and heterogeneity fracture models. All core flooding results confirmed that increased injection pressure occurred only when we used heterogeneity fracture width models and injected lower salinity during the second brine cycle. Another couple of

heterogeneous fracture experiments were preformed to gain further understanding of the effect of changing water salinity. These experiments examined the effect of increasing water salinity instead of decreasing it on injection pressure behavior. Results showed a different trend when the second water injection cycle had a salinity larger than the salinity of the first water injection cycle. The brine injection pressure decreased and in some cases continued without any change. **Figure 3.39** shows brine injection pressure measured during the first cycle injection of 0.05% NaCl and the second cycle of 1% NaCl. The brine injection pressure continued to decrease which differed from the expected results as shown in **Figure 3.36** to **Figure 3.38**. This implies that not always the changes in salinity within heterogeneous fractures lead to an increase in water injection pressure.

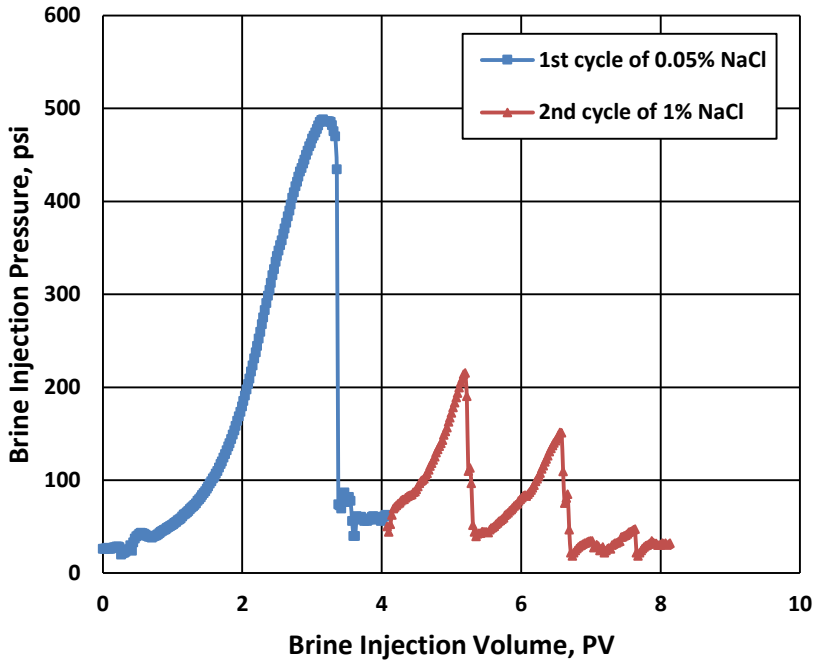


Figure 3.39. Brine Injection pressure for two brine cycles using single fracture heterogeneity model first design.

Figure 3.33 to **Figure 3.39** indicated that PPG resistance to water flow increases only if two conditions exist: heterogeneous fracture and formation water with salinity less than PPG salinity.

To answer the second question, PPG samples from effluent were taken regularly after each injection process to measure their size, strength, and changing volume. **Table 3.12** lists results of PPG sizes, gel strengths, and PPG volume ratios determined from uniform fracture experiments and single-fracture heterogeneity model (first design experiments). Two gel strengths were used in the single-fracture heterogeneous model experiments to investigate the effect of increase or decrease in brine salinity on injection pressure. During PPG injection, PPG dehydrates and became more concentrated within fractures, and this behavior causes injection pressure to increase along fractures. This conclusion was confirmed by comparing gel strength measurement for PPG before and after injection. PPG strength increased after injection, and this increase continued when PPG was injected through heterogeneous fracture. PPG swollen in 1% NaCl had a strength of 850 pa, which increased to 916 pa and 1010 pa after being injected through uniform fracture and heterogeneous fractures, respectively. Few samples of PPG at effluents were taken and placed in the same brine compositions to determine how swollen PPG volume could be increased again after extrusion from fractures. Results showed that PPG volume within brine solution increased indicating that PPG loses some of their water during PPG injection through fracture. These two results from strength and volume ratio measurements showed that PPG concentrated along fractures because of dehydration. Results also showed that PPG sizes decrease during injection based on gel strength and ratio of Dg/Wf.

During brine injection, PPG strength and particle size within fractures were changed based on the injection brine salinity. This change in gel strength and particle size caused brine injection pressure to either increase or decrease. In a uniform fracture experiment model (1.752 mm), injecting low salinity (second cycle 0.05% NaCl) did not change the brine injection pressure (**Figure 3.33**) because PPG became weaker and its particle sizes were not big enough to increase injection pressure. During the second brine cycle, PPG strength decreased to 525 pa and its size increased to 2.50 mm. In heterogeneous fracture experiments, injecting low salinity (with second cycle of 0.05% NaCl) increased the injection pressure in the second injection cycle (**Figure 3.36**) because PPG sizes were big enough to increase injection pressure regardless of the decreasing gel strength. PPG particle size was increased to 1.4 mm which is approximately two times the fracture width at choke point (0.774 mm). Finally, when brine salinity increased (in second cycle using 1% NaCl), injection pressure decreased (**Figure 3.39**) because PPG size (0.93 mm) was approximately equal to fracture width (0.744 mm) and thus did not significantly reduce the flow of water.

As for injection velocity, we are still investigating effect on PPG resistance to water flow.

Table 3.12. Summaries of PPG properties after being produced from fractures.

Experiments models	Injection Steps	PPG size, mm		PPG strength, Pa		Volume ratio increase, mL/mL
		Before Injection	After Injection	Before Injection	After Injection	
Uniform fracture width of 1.752 mm	PPG (swollen in 1% NaCl)	3.2	1.65	850	916	1.38
	1st cycle 1 % NaCl		1.75		803	
	2nd cycle0.05 % NaCl		2.50		525	
Single-fracture Heterogeneous (First Design)	PPG (swollen in 1% NaCl)	3.2	0.83	850	1010	1.7
	1st cycle 1% NaCl		0.92		789	
	2nd cycle 0.05 % NaCl		1.4		508	
Single-fracture Heterogeneous (First Design)	PPG (swollen in 0.05% NaCl)	4.8	0.98	517	640	2.05
	1st cycle 0.05% NaCl		1.13		529	
	2nd cycle 1 % NaCl		0.93		822	

4. CONCLUSIONS AND RECOMMENDATIONS

4.1. CONCLUSIONS

Several factors affect PPG injection and blocking efficiency through open fractures, were examined in this study. The results obtained from fracture experiments were based on assumptions used during the design of these fracture models. The following conclusions can be drawn from the research:

I. Brine concentration had a significant effect on the PPG swelling ratio. PPG swelled in low brine concentration had higher swelling ratios than PPG swelling in high brine concentration. In contrast, PPG sizes affect PPG swelling dynamic but had an insignificant effect on the equilibrium swelling ratio when they were swollen in same brine salinity.

II. PPG strength was determined to strongly depend on brine concentrations; PPG swelled in high brine concentrations were stronger than PPG swelled in low brine concentration. PPG with different sizes had the same gel strength when they were swollen in the same brine concentrations.

III. Fully swollen PPG increased in size (re-swell) if they contacted with lower brine concentrations. In contrast, fully swollen PPG decreased in size (deswelled) if they contacted with higher brine concentration. In field application conditions, PPG will finally get the swelling ratio of the formation water not the one it was swelled in or prepared with.

IV. In field applications, it is very common for operators to be concerned about particle size for better injection performance. Contrary to conventional concepts

in PPG treatment practices, PPG injection was more sensitive to the strength of PPG than the size of PPG. PPGs swelled in low brine concentration were larger in size than the PPGs swelled in high brine concentration. Yet, they had better injectivity through fractures because of gel strength effect. Also, PPG injection pressure did not increase linearly with injection velocity, but instead injection pressure started to curve when injection velocity exceeded 500 ft/day.

V. Choke point within fracture caused PPG injection pressure to increase as the heterogeneity within fracture geometry increased. The injection pressure drop across this point was greater than any point along fractures. Stable injection pressure can be the same based on choke point location.

VI. The selective penetration of PPG into non-cross flow heterogeneous fractures can be controlled based on fracture width ratio and gel strength. PPG strength of 870 pa and above would not flow into small fractures if large fracture width was four times equal or greater than small fracture width. When strong PPG is used, less percentage of PPG volume will flow into small fracture widths compared to weak PPG.

VII. PPG resistance to water flow within fractures were controllable. PPG with high strength and large size were more efficient at controlling water flow within fracture. Change in salinity within reservoirs can improve PPG blocking efficiency if formation water concentration is less than brine concentration used to swell PPG.

4.2. RECOMMENDATIONS

In the whole work, stainless tubes were used to simulate fractures. These tubes had a smooth inner surface, which was different from rough surface in real fractures. Fractures that manufactured in cores or rocks are recommended to be used in the future work.

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